Agenda Date: 7/16/03
Agenda Item: 2A

STATE OF NEW JERSEY
Board of Public Utilities
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ENERGY

IN THE MATTER OF THE VERIFIED PETITION OF ROCKLAND ELECTRIC COMPANY FOR THE RECOVERY OF ITS DEFERRED BALANCES AND THE ESTABLISHMENT OF NON-DELIVERY RATES EFFECTIVE AUGUST 1, 2003	)	FINAL DECISION AND ORDER DOCKET NO. ER02080614
IN THE MATTER OF THE VERIFIED PETITION OF ROCKLAND ELECTRIC COMPANY FOR APPROVAL OF CHANGES IN ELECTRIC RATES, ITS TARIFF FOR ELECTRIC SERVICE, ITS DEPRECIATION RATES, AND FOR OTHER RELIEF	)	DOCKET NO. ER02100724

(SERVICE LIST ATTACHED)

BY THE BOARD:

This Final Decision and Order memorializes and provides the reasoning for the action taken by the Board of Public Utilities ("BPU" or "Board") in the above captioned matters, by a vote of five Commissioners at its July 16, 2003 public agenda meeting, which action was summarized in the Board's Summary Order dated July 31, 2003. This Final Decision and Order supersedes the Board's July 31, 2003 Summary Order.

TABLE OF CONTENTS

Page No.

I. BACKGROUND

These matters concern petitions filed by Rockland Electric Company ("RECO," "Rockland" or "Company") requesting: (1) recovery of its deferred balances and the establishment of non-delivery rates ("deferred balances case"); and (2) approval of changes in electric rates, including changes to its tariff for electric service, its depreciation rates and other relief ("base rate case").

RECO is a wholly owned subsidiary of Orange & Rockland Utilities ("O&R"). O&R and Consolidated Edison Company of New York, Inc. ("Con-Ed") are both wholly owned subsidiaries of Consolidated Edison Inc. ("CEI"). RECO is engaged in the retail distribution and sale of electricity to approximately 70,000 residential, commercial and industrial customers within its service territory, which includes parts of Bergen, Passaic and Sussex Counties in New Jersey, and prior to restructuring obtained all of its energy requirements under a power purchase agreement ("PPA") with O&R.

Before considering the record that has been developed in these matters, a brief description of the events leading to these filings is provided below.

On February 9, 1999, the Electric Discount and Energy Competition Act, N.J.S.A. 48:3-49 et seq. ("EDECA" or "Act") was enacted. Among other things, EDECA required the Board by Order, to provide that by no later than August 1, 1999, each electric utility provide retail choice of electric power suppliers for all its customers, N.J.S.A. 48:3-53(a); unbundle its rate schedules, N.J.S.A. 48:3-52(a); reduce its aggregate level of rates for each customer class by no less than five percent, N.J.S.A. 48:3-52(d)(2); provide basic generation service ("BGS"), at approved rates, for customers who do not choose an alternate power supplier, N.J.S.A. 48:3-52(b); provide approved "shopping credits," to be deducted from the bills of customers who choose an alternate power supplier, N.J.S.A. 48:3-52(b); implement a Societal Benefits Charge ("SBC"), to recover the cost of previously approved social, environmental, and demand side management ("DSM") programs, which were included in the utilities' bundled rates, N.J.S.A. 48:3-60(a); and (2) implement a Market Transition Charge ("MTC"), to allow each utility the opportunity to recover an approved level of stranded costs, N.J.S.A. 48:3-61.

Prior to the enactment of EDECA, the movement toward energy market competition was already underway. The New Jersey Energy Master Plan Phase I Report, released in March 1995, presented a vision for the State in which energy markets in New Jersey would be guided by market-based principles and competition. Thereafter, after conducting extensive proceedings, on April 30, 1997, the Board issued an Order adopting and releasing a report entitled: Restructuring the Electric Power Industry in New Jersey: Findings and Recommendations, BPU Docket No. EX94120585Y, dated April 30, 1997 ("Final Report," also referred to as the "Green Book"). The Final Report was submitted to the Governor and the Legislature for their consideration. In anticipation of restructuring legislation to be developed and enacted, the Board's April 30, 1997 Order directed each of the State's four investor owned electric utilities to make three filings by July 15, 1997. These filings included a rate unbundling petition, a stranded costs petition, and a restructuring plan.

On July 15, 1997, RECO filed verified petitions with the BPU setting forth its unbundling, stranded costs and restructuring proposals. The unbundling and stranded costs petitions were assigned BPU Docket Nos. EO97070464 and EO97070465, respectively, and were transmitted to the Office of Administrative Law ("OAL") and assigned to Administrative Law Judge ("ALJ") William Gural. The restructuring petition was assigned BPU Docket No. EO97070466, and was retained by the Board. After extensive hearings and briefing, ALJ Gural issued an Initial Decision on the unbundling and stranded costs issues in August 1998. Hearings on all four utilities' restructuring petitions were held before the Board (chaired by Commissioner Carmen J. Armenti) in April and May 1998.

On February 11, 1999, shortly after the enactment of EDECA, the BPU established guidelines and a schedule for the commencement of settlement negotiations among the parties in RECO's restructuring proceedings. Though all parties could not reach a comprehensive settlement, two proposed stipulations of settlement were filed with the BPU in July 1999. One proposed settlement ("Stipulation I") was executed by RECO and New Jersey Transit ("NJT"), and was identical to RECO's proposed Plan for Resolution of the Proceedings ("Plan"), which it had unilaterally filed with the BPU on July 13, 1999. An alternative settlement ("Stipulation II") was executed by the Division of the Ratepayer Advocate ("RPA") and the Ml.D.-Atlantic Power Supply Association ("MAPSA"). After reviewing the entire evidentiary record, including the proposed settlements and comments of the parties, as well as the requirements of EDECA, the Board issued a Summary Order dated July 28, 1999. In the Matter of Rockland Electric Company's Rate Unbundling, Stranded Costs and Restructuring Filings, BPU Docket Nos. EO97070464, EO97070465 and EO97070466 ("Summary Restructuring Order").

In its Summary Restructuring Order, the BPU modified the ALJ's Initial Decision in light of subsequent developments, finding that the elements of Stipulation I, with certain modifications and clarifications to address concerns raised by the parties, provided an appropriate framework for a reasonable resolution to the unbundling, stranded costs and restructuring filings. Among other things, pursuant to EDECA, the BPU designated a four-year "Transition Period" starting August 1, 1999, during which Board-approved unbundled rates would be in effect. The Board also ordered that RECO implement rate reductions over the Transition Period, including a 5% reduction effective August 1, 1999, a 7% reduction effective July 1, 2001 and a 10% reduction effective August 1, 2002, to be sustained until July 31, 2003. The BPU reserved judgment as to whether the costs incurred by RECO in connection with O&R's Transition Power Sales Agreement ("TPSA") and Incremental Energy Sales Agreement ("IESA"), executed with the purchaser of its generating assets, Southern Energy Affiliates, Inc. (now the Mirant Corporation ("Mirant") were reasonable and prudent.[1]

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[1] The sale of O&R's generating units was approved by the BPU in a June 24, 1999 Summary Order in Docket No. EM99030195.

The Board found that RECO was entitled to recover its reasonable and prudently incurred BGS costs, and that, to the extent the BGS charge did not cover all such costs, the difference would be subject to deferral. The Board further stated that the Company could recover its prudent and reasonably incurred restructuring related costs via a nonbypassable Market Transition Charge. RECO was also permitted to recover its Universal Service Fund ("USF"), Consumer Education Program ("CEP") and Demand Side Management costs through an SBC, and to defer costs not recovered during the Transition Period. Similarly, RECO was permitted to defer the difference between its actual above-market non-utility generation ("NUG") costs and its Energy Cost Adjustment ("ECA") recoveries.

These matters were returned to the Board's agenda on June 26, 2002, at which time, the Board determined to modify the July 28, 1999 Summary Restructuring Order in limited respects. On July 22, 2002, the Board issued a Final Restructuring Order under the same caption, which provided additional detail and rationale for its Summary Restructuring Order, and discussed the limited modifications thereto, which the Board adopted at its June 26, 2002 agenda meeting. Specifically, the Board directed that, effective on the date of the Final Restructuring Order and on a going forward basis, interest on under recovered balances should be booked at the interest rate on seven-year constant maturity treasury notes, as shown in the Federal Reserve Statistical Release on or closest to August 1 of each year, plus 60 basis points.[2] Consistent with the language in RECO's proposed Plan, the Board further directed that such interest should be calculated on the unamortized balance of the deferral on a net-of-tax basis.

The Final Restructuring Order also required RECO to make a filing with respect to the proposed level of all unbundled rate components proposed to go into effect August 1, 2003, so that the Board could consider these prior to the end of the Transition Period. (Final Restructuring Order at 65). The Company was ordered to make a filing with respect to its distribution base rates no later than October 1, 2002, and a filing with respect to all other elements of its unbundled rates, including its deferred balances, by August 30, 2002. The Board indicated that these filings would be sent to the OAL and assigned to an ALJ who would oversee both the base rate case and the deferred balance cases on two separate tracks, and ultimately consolidate the cases for the issuance of an Initial Decision, such that the Board could decide these matters on a comprehensive basis before August 1, 2003.

To assist the Board with this analysis, on July 29, 2002, the Board issued a Request for Proposals ("RFP") to secure the services of an independent accountant, auditor or consultant to conduct audits of the restructuring-related deferred balances of New Jersey's four electric utilities. The Board's overall objective was to obtain certified opinions as to whether the utilities' deferred balances were correct and included only those costs that were reasonable, prudently incurred, accurately calculated, correctly

[2] While the Final Restructuring Order left open the possibility that there would be a retroactive review of the interest rate for the entire Transition Period, subsequently, on October 16, 2002, the Board issued an Order on Motion for Reconsideration and/or Clarification in the same caption, wherein it modified its Final Restructuring Order to clarify that there would be no retroactive modification of the interest rate on RECO's deferred balances.

recorded and in compliance with all applicable Board Orders. Regarding prudence of BGS costs, the auditors were directed to determine whether the utilities pursued a prudent procurement procedure for the acquisition of BGS supply and whether, when required, they purchased power at reasonable prices consistent with market conditions in the competitive wholesale market place and consistent with appropriate hedging techniques. The auditors were also directed to comment on the utilities' mitigation efforts with regard to above-market NUG contract costs during the Transition Period. The Board directed that the RECO audit include a review of the prudence of O&R's parting contracts, executed after divestiture of its generating assets. The auditors were further required to quantify any inappropriate, unreasonable or imprudently incurred costs. The audit was to be conducted in two phases, with Phase I encompassing RECO's deferred balances from August 1, 1999, through July 31, 2002, and Phase II encompassing its deferred balances from August 1, 2002 through July 31, 2003. At its September 18, 2002 agenda meeting, the Board selected Larkin & Associates, LLC and Synapse Energy Economics, Inc. ("Auditors") to conduct the RECO audit.

On July 31, 2002, Governor McGreevey convened, by Executive Order 25, a Deferred Balances Task Force to examine "the reasons why the deferred balances were accumulated, what mitigation steps utilities took to reduce deferred balances and how they ought to be addressed to best protect the interest of ratepayers, including an evaluation of the merits of securitizing deferred balances." The task force issued its report on August 30, 2002. On September 6, 2002, the Governor signed into law Senate Bill 869, containing certain modifications to EDECA, which would allow, but not require, the BPU to permit securitization of portions of the utilities' deferred balances, subject to certain conditions being met. N.J.S.A. 48:3-51 and 48:3-62.

II. PROCEDURAL HISTORY

In compliance with the Final Restructuring Order, RECO filed its deferred balances case on August 29, 2002, and its base rate case on October 1, 2002. These petitions were transmitted to the OAL on September 12, 2002 and October 16, 2002, respectively, and consolidated for hearing before ALJ William Gural. Pursuant to N.J.A.C. 1:1-13.1, on December 3, 2002, ALJ Gural conducted a prehearing conference, in which counsel for RECO, the RPA and Board Staff ("Staff") participated. A Prehearing Order was issued on December 6, 2002, setting forth the issues to be litigated and a procedural schedule. By Order dated December 9, 2002, the ALJ granted RECO's November 27, 2002 motion for admission, pro hac vice, of John L. Carley, Esq. Motions for participant status made by Public Service Electric and Gas Company ("PSE&G") and Jersey Central Power & Light Company ("JCP&L") were also granted.

By letter dated December 12, 2002, the RPA requested changes to the Prehearing Order. Also, by letter motion dated December 12, 2002 to the Board's Secretary, the RPA requested, on behalf of all parties, that May 30, 2003 be reserved by the Board as a hearing date with respect to RECO's submittal of 12 months of actual data, which would not be available until May 20, 2003.[3] On December 17, 2002, the ALJ issued a revised Prehearing Order, in which RECO was directed to update its base rate case

[3] The test year for the base rate case was the 12-month period ending April 30, 2003.

filing with actual data according to the following schedule: “7+5” (actual/projected) data on December 31, 2002, “8+4” data on January 17, 2003 and “12+0” data on May 20, 2003. Initial discovery commenced soon after RECO’s filings, and continued up to and past the commencement of evidentiary hearings.

On December 23, 2002 the RPA filed an emergent letter motion seeking to compel RECO to provide responses to all outstanding discovery. RECO responded to the motion by letter dated December 30, 2002. The RPA filed a further reply on January 6, 2003. ALJ Gural granted the RPA’s motion by Order dated January 14, 2003.

The Auditors submitted a draft Phase I audit report to the BPU on December 23, 2002. After RECO reviewed the draft report for factual accuracy and the designation of proprietary information, the Auditors issued a Final Phase I Audit Report (“Audit Report”) on January 3, 2003. At its January 23, 2003 agenda meeting, the Board acknowledged receipt of the Audit Report and transmitted it, along with RECO’s emergent Motion For a Protective Order, to ALJ Gural for consideration in the proceedings before him. The Audit Report was sent to all parties in the base rate and deferred balances proceedings on January 27, 2003.

Upon proper notice, public hearings were held in these matters on February 10 and March 19, 2003, in Montvale. The ALJ conducted evidentiary hearings on February 20, 21, 24, 25, 27 and 28, 2003. RECO, Board Staff and the RPA participated in the hearings. In support of the deferred balances petition, RECO presented testimony from: Frank Marino (overview; BGS, ECA and SBC deferrals and recovery; restructuring costs); Joseph Holtman (BGS supply procurement, NUG contract administration, hedging); Terry Dittrich (on efforts to encourage customer choice and increase participation by third party suppliers); Edward Krapels (power price projections, TPSAs, divestiture economics); and John Perkins (securitization, asset carrying costs). In addition, the Company presented testimony in support of its base rate petition from Frank Marino (policy, revenue requirements); Robert Rosenberg (on cost of equity capital); Angelo Regan (on plant additions, capital budget and proposed expanded service reliability program); Kenneth Kosior (on wages); Richard Kane (on employee benefits); Donald Kennedy (on late payment charges, bad check charges, and reconnection charges); Charles Hutchinson (on the Company’s depreciation study); James Clawson (on construction charges); Allan Cohen (on the Company’s cost of service study); and William Atzl (on tariff design).

As to the deferred balances filing, the RPA offered as expert witnesses consultants James Cotton (on prudency of BGS procurement) and James Rothschild (on securitization/amortization of the deferred balances). By letter dated February 4, 2003, the RPA advised ALJ Gural and the parties that it would present Paul Chernick as an additional witness to address the Audit Report. RECO opposed the RPA’s request to add Mr. Chernick. On February 14, 2003, ALJ Gural issued an Order denying the RPA’s request to add Mr. Chernick as a witness. Subsequently, the RPA filed a motion for interlocutory review with the Board, seeking expedited treatment and reversal of the ALJ’s denial of its motion to add a witness. RECO filed a response in opposition on February 19, 2003. The Board considered this matter at its February 20, 2003 agenda meeting, and issued a written Order dated February 27, 2003, granting the RPA's motion for interlocutory review and reversing the ALJ's denial of its motion to add a witness.

As to the base rate case issues, the RPA offered as expert witnesses consultants James Rothschild (on cost of capital/rate of return); Robert Henkes (on revenue requirements); Michael Majoros (on depreciation); and David Peterson (on cost of service/tariff design).

The parties filed initial and reply briefs on March 18, 2003 and April 1, 2003, respectively. On March 26, 2003, Staff moved to supplement the record with certain documents concerning its analysis of consolidated federal income tax benefits. On April 10, 2003, RECO filed a letter in opposition to Staff's motion and cross-moved to strike portions of Staff's reply brief and appendix. As part of its opposition papers, the Company responded to and rebutted Staff's analysis concerning consolidated taxes. By Order dated April 17, 2003, the ALJ granted Staff's motion to supplement the record and denied RECO's cross-motion to strike.

By letter from the Board's Secretary dated March 25, 2003, the Board advised the four ALJs presiding over the various electric utilities' deferred balances proceedings that on March 20, 2003, it had voted to recall certain issues from the pending deferred balances cases. More specifically, the Board recalled issues related to the securitization/amortization of the deferred balances, including the issue of how much of the prudently incurred deferred balances should be securitized and how much should be amortized, and for those balances to be amortized, the appropriate length of the amortization period and the interest rate. The Board also recalled the issue of whether all or part of the prudently incurred deferred balances are legally eligible for securitization. The Board indicated that it would consider proposals made by the parties for interim recovery of the deferred balances pending the Board's final decisions on the individual utilities' securitization petitions[4] and the issuance of any transition bonds approved by the Board. The ALJs were still requested to make findings regarding the levels of prudently incurred deferred balances for each utility.

On June 12, 2003, ALJ Gural filed his Initial Decision with the Board. Thereafter, Exceptions and Replies to Exceptions were filed by the parties. These will be described in more detail below.

On June 23, 2003, RECO filed a letter with the Board indicating that the parties all agreed to the introduction of the "12+0" updates into the record without the need for an additional hearing. The Board **<u>HEREBY</u> <u>ACCEPTS</u>** both RECO's and the RPA's "12+0" updates into evidence.

[4]RECO filed a petition for a Bondable Stranded Cost Rate Order for the issuance of up to $68 million of transition bonds on November 8, 2002, BPU Dkt Nos. EF02110852 and ER02080614 ("Securitization Petition"), which was retained by the BPU for direct hearing. The Securitization Petition was subsequently twice amended and a hearing in this matter was held at the Board, before Commissioner Jack Alter, on February 5, 2004.

On July 11, 2003, RECO filed with the Board a proposed settlement position for its consideration. The proposed "settlement" was executed only by the Company. Moreover, the settlement proposal was submitted after the date for the filing of exceptions and reply exceptions and, thus, after the record closed. Accordingly, RECO's belated submission will not be addressed in this Order.

III. INITIAL DECISION

On June 12, 2003, ALJ Gural filed his Initial Decision ("I.D.") with the Board. The I.D. contains a procedural history and a summary of RECO's filings, a summary and analysis of the record, and the ALJ's findings with respect to the numerous litigated issues in this consolidated proceeding. Key elements of the I.D. are summarized below.

A. Deferred Balances Case

As discussed supra, pursuant to EDECA, the Summary and Final Restructuring Orders permitted RECO to defer on its books the unrecovered balances of certain specified costs incurred during the Transition Period. RECO's deferred balances filing (updated by letter to the Board dated July 3, 2003) seeks to recover projected deferred balances aggregating $97.2 million, including interest of $8.9 million, as of July 31, 2003, comprised of the following items:

Basic Generation Service	$102.0 Million
Energy Cost Adjustment	(9. 5)
Societal Benefits Charge	2.8
Restructuring Proceeding Costs	1.9
Total Net Deferral Balance	$ 97.2 Million

Based upon data in the record as of June 10, 2003, the ALJ concluded that the amount of RECO's deferred BGS balance eligible for rate recovery should be $84,650,000 including interest of $7,417,000. (I.D. at 29). His disallowances included $5,817,000, representing half of the Company's hedging costs, and $8,185,000 in costs incurred as a result of O&R's failure to extend the energy portion of the TPSA at the time it sold its generation assets.

The specific deferred balances issues addressed by the ALJ and the parties' positions with respect thereto are summarized below.

1. BGS Deferred Balance

In its initial deferred balances petition, RECO proposed to recover its BGS deferral, estimated at that time to be $110.5 million by the end of the Transition Period, including interest of $15.334 million, over a four-year period, through a nonbypassable Transition Recovery Charge. RECO's proposal was estimated to result in an increase of 27.9%. Alternatively, if the Board were to adopt RECO's request to securitize its BGS deferred balance via the issuance of transition bonds, the costs of which would be recovered over a 15-year period, RECO proposed a 12% increase. (Petition (RECO-1) at 27). In its update filed with the Board on December 31, 2002 reflecting actual data through November 2002 (RECO-2), RECO sought to recover $100,536,000. (I.D. at 28). In a further update filed with the Board on July 3, 2003 reflecting actual data through May 2003, the projected BGS balance increased slightly, to $102,003,000 including interest.

The RPA proposed various disallowances which would reduce the recoverable BGS deferred balance to $55,157,000, including a $28,345,000 reduction to reflect RECO's assertedly unreasonable and imprudent failure to timely transfer its load from the New York Independent System Operator ("NYISO") to the PJM Interconnection LLC ("PJM ISO" or "PJM"); and a disallowance of $10,354,000 of hedging costs. (I.D. at 18-19).

In its Reply Brief, Staff recommended that the BGS deferred balance be reduced to $81,308,000, reflecting among other adjustments, a revised interest calculation, an $8,185,000 adjustment for failing to have extended the energy component of the TPSA through August 2000, a $5,817,000 disallowance of hedging costs, and a $2,213,000 adjustment for an asserted 6 month delay in joining PJM. (SRB, Appendix SRB-1 at 1).

The ALJ concluded that RECO should be permitted to recover $ 84,650,000 as its prudently incurred BGS deferred balance. (I.D. at 29). The ALJ determined to disallow $5,817,000 of hedging costs and $8,185,000.00 as a result of O&R's failure to extend the energy portion of the Transition Power Supply Agreement at the time it sold its generation assets. These adjustments are more fully explained below.

a) The PJM Transfer Issue

The record reflects that prior to March 1, 2002, wholesale power in RECO's service territory was obtained through the NYISO. On March 1, 2002, following receipt of Federal Energy Regulatory Commission ("FERC") approval, RECO transferred its Eastern Division, representing approximately 90% of its load, from the control area of the NYISO to PJM. (RECO- 7 at 4). This transfer permitted RECO to take part in the New Jersey statewide BGS auction, which resulted in a Board-approved competitively procured supply for the final year of the Transition Period. RECO's Central and Western Divisions remain within the NYISO control area.

The RPA contended that RECO should have transferred its Eastern Division from the NYISO to PJM much sooner than it did, i.e., by August 1, 1999, the beginning of the Transition Period, as compared to the actual transfer date of March 1, 2002. RPA witness Cotton opined that RECO's failure to timely join PJM resulted in excessive BGS costs to customers. In support of his conclusion that RECO waited too long to transfer to PJM, he testified that: (1) the substantially lower cost of PJM energy purchases relative to those from the NYISO were evident as early as 1999; (2) as early as 1997 RECO knew its parent company planned to divest its generating units, and should have started its PJM investigation at that time; (3) RECO should have been alerted by its mounting BGS deferral in the first year of the Transition Period that it needed to reduce the cost of its BGS supply; and (4) RECO was aware well before March 1, 2002, that retail choice had failed to develop in its service territory, which should have led it to realize it would need to provide BGS for the foreseeable future and to plan accordingly. In addition, witness Cotton noted that it was not until June 2001 that RECO performed an economic study of the costs and benefits of the transfer to PJM, which by then showed millions of dollars of savings. (R-4 at 23-26). The RPA alleges that RECO missed potential BGS savings of approximately $28,345,000, plus interest. The RPA further contended that had the Company switched to PJM in a timely manner, the high cost of TPSA and IESA contracts would have been unnecessary (saving RECO another $949,000, plus interest) and hedging costs of approximately $10,354,000, plus interest, would have been avoided.

Although Staff agreed that RECO's shift from the NYISO to the PJM ISO should have been more timely, it found the RPA's disallowance to be excessive. Staff noted that the Audit Report did not find the timing of RECO's transfer to PJM to be unreasonable or imprudent. However, in Staff's judgment, while it was unrealistic to assume that RECO could have switched to PJM as early as August 1999, the transfer could have been accomplished six months sooner than the March 2002 date. Staff asserted that two months could have been saved if RECO had not waited until it received final FERC approval before beginning to install necessary metering and communication equipment. Staff opined that installation of this equipment should have been underway in parallel with the FERC filing on the assumption the FERC would approve the transfer. Staff recommended a reduction in RECO's deferred balance of $2.2 million, based on the quantification of the impact of the delay shown in Appendix F to RPA Exhibit R-4. (Staff's Initial Brief ("SIB") at 15 -17).

The ALJ adopted the position of the Auditors and found that RECO was not imprudent in the timing of its transfer from the NYISO to the PJM ISO. He concluded that there was "sufficient uncertainty over energy pricing during the transition period" and that the RPA's position "relies upon hindsight to criticize the company's reluctance to move more expeditiously." (I.D. at 21-22, 28). He further disagreed with Staff's assertion that RECO should have been installing equipment while FERC approval was pending, since there was no assurance at the time that the FERC would approve the transfer.

The ALJ also found that RECO witness Marino "correctly interprets the ratemaking treatment of the $325,000 internal labor and overhead costs incurred by the PJM transfer, a sum not contemplated in RECO's last base rate." He accordingly concluded that this amount should be included in the deferred balance. (I.D. at 20).

b) Parting Contracts and Hedging Costs

The Auditors found that O&R was imprudent for failing to negotiate a multi-year parting contract with Mirant, the purchaser of O&R's generating units. According to the Auditors, as a result of this failure, RECO's customers were exposed almost completely to the nascent NYISO spot market following the expiration of the TPSA in October 2000. (Exhibit S-8 at 30). As evidence that such an extended contract could have been secured, the Auditors cited several multi-year parting contracts entered into by the other New York utilities upon divestiture of their generating units, and the approval of these contracts by the New York Public Service Commission ("NYPSC").

The Auditors proposed a disallowance of $26.8 million related to the failure to negotiate longer parting contracts and hedging costs that the Auditors maintained would not have been incurred had the Company done so. O&R entered into two parting contracts with Mirant that allowed O&R to purchase replacement energy at relatively favorable prices from Mirant through April 2000, and capacity through October 2000. Under RECO's power purchase agreement with O&R, RECO's share of these purchases was approximately 35%. After reviewing RECO's spot market and contractual purchases during the first three years of the Transition Period, the Auditors concluded that O&R imprudently failed to negotiate longer parting contracts with Mirant. The Auditors asserted that the parting contracts should have been for a term of three years, i.e. through June 2002. The Auditors further asserted that had O&R entered into such multi-year transition power purchase agreements to prudently protect the customers of RECO from energy price volatility, the hedging agreements would have been unnecessary and RECO's energy, capacity and hedging costs would have been reduced by a net $26.8 million.

While Staff agreed with the Auditors that O&R could and should have negotiated more favorable parting contracts and that a disallowance was appropriate to reflect RECO's imprudence, it opined that the Auditors' proposed $26.8 million disallowance was too high. Accepting the Company's argument that Mirant was unwilling to extend the TPSA through June 2002, Staff cited RECO's own testimony that Mirant was willing to agree to an extension of the parting contracts of "a few months," as justification for a more modest disallowance. Given that the months in question were the summer months of May, June, July and August 2002, Staff asserted that O&R was particularly imprudent for not capitalizing on Mirant's offer to extend the parting contracts for the summer months. Based on the Auditors' quantification, Staff recommended that $8.185 million of RECO's deferred BGS balance be disallowed for O&R's failure to effectively capitalize on its parting contract opportunities. Additionally, noting that the use of hedging as a risk management tool can be costly and that, as RECO discovered, forward prices can be above, and in some instances, substantially above, the so-called "settled price" in a given delivery month, Staff recommended that RECO's hedging costs should be shared equally between ratepayers and shareholders. Accordingly, Staff recommended that RECO's BGS deferral be reduced by one half of the $11.594 million of hedging costs (or $5,817,000) incurred by RECO through July 31, 2002. (SIB at 35).

The ALJ agreed with the Auditors' recommendation that the Company's BGS deferred balance be reduced to reflect the impact of O&R's imprudent failure to negotiate a longer term parting contract. He concluded that this is "an area where the company should have behaved more prudently." (I.D. at 23). The ALJ did not adopt the full level of disallowance quantified and recommended by the Auditors to reflect the failure to enter into a three-year parting contract, but rather accepted Staff's more modest $8.185 million disallowance for O&R's failure to extend the energy portion of the TPSA with Mirant through August 2000. (I.D. at 25). Although RECO argued that there was no evidence to show that Mirant would have extended the term of the TPSA, the ALJ accorded greater weight to evidence that other New York electric utilities were able to negotiate longer term TPSAs. (I.D. at 21-25). The ALJ also agreed with Staff that the increased hedging costs should be shared with ratepayers and thus only recommended a disallowance of one half the hedging costs, or $5,817,000, rather than the full amount as recommended by the Auditors and the RPA. (I.D. at 25).

2. Consumer Education Program

Pursuant to N.J.S.A. 48:3-60(a)(5), RECO sought to recover $446,000 as its share of CEP costs, which is included in its SBC. The CEP was initiated, pursuant to N.J.S.A. 48:3-85(d), to educate New Jersey gas and electric customers about their opportunity to select alternate suppliers of gas and electricity. The RPA recommended disallowance of RECO's CEP costs on the grounds that RECO failed to show that the CEP costs were reasonably and prudently incurred. The RPA did not challenge the specific amount sought by RECO, rather it noted that there had been no Board scrutiny of CEP costs and that RECO had not met its burden of proof to demonstrate that these expenses were reasonably and prudently incurred. (RPA Initial Brief ("RIB") at 45-6). Staff took no position on this issue.

The ALJ denied the RPA's proposed CEP adjustment and found that RECO was entitled to recover $446,000 as its share of the CEP costs. (I.D. at 25-26). In support of his conclusion, he noted that RECO provided evidence in the form of a Verified Petition for a declaratory ruling, dated August 11, 2000, indicating that the Board hired the Center for Research and Public Policy ("Center") to research the efficacy of the CEP. (RECO-66). The Verified Petition indicates that the Center, in its third report, asserted that all measures through April 1, 2000 were met or exceeded. The Board approved this report on May 25, 2000. The ALJ further noted that in prior Board Orders with respect to the CEP dated June 24, 1999, August 9, 1999, October 15, 1999, February 2, 2000, May 25, 2000, June 23, 2000, no negative language appears concerning RECO's conduct of its CEP program. (I.D. at 26).

3. Post-Transition Period Adjustments

Included in RECO's original filing was an $8.6 million over-collection, including interest, in the ECA, which represents the recovery of above market NUG contract costs. RECO proposed to use the over-collection to offset other costs, specifically, to credit $3.7 million toward projected above-market NUG costs over the remaining lives of the NUG contracts, while leaving the ECA at its existing level and continuing to use deferred accounting with interest. (RECO Initial Brief ("CIB") at 61). The remaining ECA over-collection would be utilized to offset deferred Restructuring Proceeding costs of $1.7 million and $1.6 million of excess refunds provided to customers by a temporary credit, which expires July 31, 2003. The petition also reflected increases to recover a net deferred SBC balance of $1.4 million, after reflecting an offset of $1.6 million of ECA over collection. The MTC would continue to remain at zero as it has over the term of the Transition Period. (RECO- 7, FPM-1 at 3-4).

The RPA opposed RECO's proposal to offset the ECA over-recovery by future under-recoveries. (RIB at 40). It argued that by offsetting over-collections from ratepayers over the past four years with five years of estimated future costs, the ratepayers are deprived of interest on the over-collected ECA for the next five years. In addition, using data from RECO-2, FPM-1 at 3, the RPA also opposed RECO's proposal to offset over-recovered NUG costs against the Temporary Credit Excess Refund. The Temporary Excess Credit Refund, due to expire July 31, 2003, was designed to refund to customers: (1) the ratepayers' share of divestiture gains of $1,420,000; and (2) $851,000 due to changes in depreciation rates or credits due ratepayers as a result of RECO's Final Restructuring Order. The total for these amounts is $2,271,000. However, over the Transition Period, RECO refunded $3,935,000, or $1,664,000 more than it should have. The RPA attributed the higher refund to the Company's accounting errors and urged that the $1,664,000 be added to the deferred balance to be amortized over 10 years.

The ALJ adopted the RPA's position on this issue and found that RECO should use the $3.7 million over-recovered NUG costs collected through the ECA to reduce the BGS deferral rather than as an offset to future NUG costs. (I.D. at 27). He further found that RECO should add the $1,664,000 Temporary Excess Credit refund to the deferred balance rather than use it as an offset to the over-recovered NUG costs. In summary, the ALJ concluded that: "RECO should not be permitted to set off its under-collection with its over-collected deferred ECA balance." Id.

B. Base Rate Case

As noted above, RECO filed its base rate petition on October 1, 2002, seeking an increase in rates to produce additional revenues totaling $7,276,000 or 5.5%, including an overall rate of return of 9.43%. This amount was based on 3 months actual and 9 months estimated data for the test year, which was the twelve months ended April 30, 2003. In its Exhibit RECO-11A, P-2 Summary "8+4" update, the additional revenue requirement was reduced to $6,332,000. On May 21, 2003, RECO further modified its requested increase based on 12 months actual data for the test year ended April 30, 2003. RECO's adjusted 12 months actual data shows a revenue increase of $3,156,000, or 2.3%, including an overall rate of return of 9.33%. The positions of the parties based upon updated twelve-month actual data, as well as the ALJ's Initial Decision (updated for "12+0") data) are summarized below.

	COMPANY	RPA	STAFF	ALJ
RATE BASE ($000s)	$129,092	$109,855	$110,827	$112,156
RATE of RETURN	9.33%	7.92%	7.90%	9.33%
OPERATING INCOME REQUIREMENT	$ 12,042	$ 8,705	$ 8,757	$ 10,460
PRO FORMA OPERATING INCOME	$ 10,181	$ 12,708	$ 12,592	$ 12,481
OPERATING INCOME DEFICIENCY	$ 1,861	$ (4,003)	$ ($3,835)	$ (2,021)
RETENTION FACTOR[5]	0.5905	0.5905	0.5905	0.5905
REVENUE REQMNT	$ 3,156	$ (6,779)	$ (6,494)	$ (3,423)

The ALJ adopted RECO's proposed overall rate of return but recommended an overall distribution rate decrease of $3,423,000, resulting in a 2.49% decrease in revenues.[6] Key elements of the I.D. and the position of the parties are summarized below.

1. Rate of Return

The ALJ adopted RECO's position on this issue and concluded that RECO's return on equity "should not be less than 12% and that the overall rate of return should be 9.43%."[7] (I.D. at 37). RPA witness Rothschild recommended a return on equity of 9.25% and Staff recommended a 9.5% return on equity. In adopting RECO's position on this issue, the ALJ concluded that the Company still faces regulatory risks, which justify its proposed level of return. (I.D. at 36).

2. Rate Base

The ALJ adopted many of the Staff and the RPA's recommendations for the rate base issues in this proceeding, including the following exclusions from rate base: (1) the Darlington and Upper Saddle River projects; (2) RECO's enhanced service reliability program; and (3) unamortized balances related to deferred research and development, audit costs and the deferred Ramapo property taxes. (I.D. at 38-42). As shown in the above schedule, the ALJ's findings and conclusions result in a rate base of

[5] To provide for income taxes and uncollected amounts. The revenue requirement is determined by dividing the operating income deficiency by the retention factor.

[6] Although a "12+ 0" chart is presented here, the ALJ's Decision as filed was based on "8+4" numbers.

[7] This number becomes 9.33% when updated for twelve months of actual data.

$112,156,000 (based on 12 month actual test year data). The key rate base issues discussed by the ALJ are briefly summarized below.

a) Utility Plant In Service ("UPIS")

RECO requested to include certain post-test year plant additions in rate base, which it maintained are "known and measurable." The Company contended that although the additions to the Oakland Substation, the Upper Saddle River Substation and Distribution System, and the Darlington Substation are scheduled to be completed after the end of the test year, these capital additions are still "known and measurable" and appropriate for inclusion in rate base. Accordingly, RECO requested recognition of $201,055,000 in UPIS.

The RPA argued that all of the proposed plant additions should be rejected. As to the Darlington project, RPA witness Henkes noted that this project has a projected cost of $16 million, and makes up over 60% of the total projected post-test year plant additions, yet construction is not scheduled to start until after the April 30, 2003 end of the test year and the project is not expected to be completed until May 2004 at the earliest. In addition, the RPA contended that none of the projected post-test year plant additions meet the "known and measurable" standard, which requires that projections must be carefully quantified through proofs which manifest convincingly reliable data. (RPA Initial Base Rate Case Brief at 36, citing I/M/O Elizabethtown Water Company, Decision on Motion for Determination of Test Year and Appropriate Time Period for Adjustments ("Elizabethtown"), BPU Docket No. WR85040330 dated December 23, 1985).

In reducing UPIS to $180,261,000, the ALJ adopted Staff's recommendations, finding that the Oakland project meets the requirements for post-test year inclusion in rate base because it is expected to be in service June 2003, but that the Upper Saddle River ($4,296,000) and Darlington ($15,274,000) projects should be disallowed because they do not satisfy the Board's requirements for post-test year additions established in Elizabethtown. (I.D. at 38).

b) Cash Working Capital ("CWC")

The ALJ noted that the purpose of the CWC component of rate base is to compensate the utility for funds it provides to pay expenses in advance of receipt of revenues. (I.D. at 39). He further noted that the Board supports the use of a "lead-lag study" as the most precise method of ascertaining the proper level of CWC. The lead-lag study measures the difference in the time frames between: (1) when services are rendered and revenues for those services are received; and (2) when the cost of labor, materials, etc. used in providing services is incurred and recorded and when they are actually paid for by the Company.

The ALJ adopted Staff's recommendations that depreciation and amortization expenses be included in the lead/lag study and assigned a zero lag as proposed by RECO, and that deferred federal income taxes and investment tax credits be excluded from the calculation as proposed by the RPA. He further concurred with Staff and rejected the

RPA's position that the return on common equity should be removed from the lead/lag study. In support of these findings, the ALJ cited to Exhibit P-3, Schedule 8 of Staff's Initial Brief. He also noted that Staff's positions on these issues have been adopted by the Board in several prior Orders. (I.D. at 39-40).

c) Deferred Board Audit Costs & Ramapo Property Tax Excess Refund

RECO sought to include $56,000 in rate base representing the unamortized balance (net of deferred taxes) of certain research and development ("R&D") expenditures associated with a cancelled coal burning technology project. In addition, RECO requested a three-year amortization ($175,000 annually) of BPU Audit Costs of $353,000 for a 1993 Management Audit, $96,000 for an Electric System Reliability Audit and $77,000 for a Competitive Services Audit. Under its proposal, RECO would also include in rate base the after-tax unamortized balances of $153,000 for the 1993 Management Audit, $42,000 for the Electric System Reliability Audit and $33,000 for the Competitive Services Audit.

RECO also requested a three-year amortization of a $154,000 excess refund it provided to customers in 1998. At that time, in the context of its 1998 Levelized Energy Adjustment Clause ("LEAC") proceeding, RECO voluntarily returned to ratepayers its share of a property tax refund it received from a challenge by O&R to the level of property taxes assessed by the town of Ramapo, New York on taxable plant allocable from O&R to RECO through the Power Supply Agreement. The LEAC became effective on June 19, 1998, and was expected to provide the mechanism to flow back the property tax refund over a 12-month period. However, the 1998 LEAC remained in effect through July 31, 1999 (when it was terminated by the Summary Restructuring Order), thus creating the excess refund. In addition to the amortization of the $154,000, RECO sought to earn a return on the unamortized, after-tax balance of $67,000.

With regard to the R&D expenditures, the ALJ agreed with Staff and the RPA that RECO should not receive rate base recognition of its $56,000 unamortized balance, since the Board already approved a Stipulation signed by the Company in its last base rate case agreeing to a 20-year amortization of these expenses. [Exhibit R-18 - <u>I/M/O the Petition of Rockland Electric Company for Approval of an Increase in Electric Rates</u>, BPU Docket No. ER91030356J, dated January 23, 1992 (approving Stipulation dated January 10, 1992, Appendix A, Page 3 of 4)]. (I.D. at 42).

The ALJ also agreed with Staff and the RPA that the inclusion of unamortized balances in rate base is contrary to Board policy and should therefore be denied. In denying recognition of the after-tax unamortized balances of $153,000 for the 1993 Management Audit, $42,000 for the Electric System Reliability Audit and $33,000 for the Competitive Services Audit, he cited the Board's Order in <u>I/M/O Petition of New Jersey Natural Gas Company</u>, BPU Docket No. GR89030335J, dated July 17, 1990. (I.D. at 42).

With respect to the current year portions of the 1993 Management Audit Costs and the Electric System Reliability Audit, the ALJ adopted RECO's and Staff's position that these costs are proper for inclusion in rate base. While RPA witness Henkes testified that these costs represent newly introduced expense adjustments with no supporting testimony as to why these costs were incurred, the ALJ, relying on an argument made by Staff, concluded that N.J.S.A. 48:2-16.4 provides that "reasonable audit expenses are considered legitimate business expenses of the utility." (I.D. at 41-42).

There was no consensus among the parties on the amortization period for these items. As previously stated, RECO recommended a three-year amortization. The RPA argued that a five-year amortization is more appropriate and reasonable based upon the fact that the Company's last base rate proceeding was more than 11 years ago. (RIB at 66). Staff recommended using a four-year amortization, consistent with other amortization recommendations it has made in this matter. It further opined that setting the amortization period based upon the approximately 12-year life of the current rates was inappropriate, given the restructuring of the electrical utilities under EDECA and the resulting rate caps during the four-year Transition Period. (SIB at 62). While he did not explicitly rule on this issue, the ALJ implicitly adopted Staff's four-year amortization recommendation.

d) Net Pension/Other Post-Employment Benefits ("OPEB")

RECO proposed to return a prior period over-recovery of pension expense to customers over a three-year period and to deduct the unamortized balance from rate base. The parties agreed that this adjustment is appropriate. The only dispute concerns the appropriate amortization. RECO proposed a three-year amortization, Staff proposed four years and the RPA proposed five years. The ALJ adopted Staff's position as reasonable. (I.D. at 43).

e) Accumulated Deferred Income Taxes ("ADIT")

RECO included an ADIT balance of $16,615,000 as a rate base deduction. The RPA and Staff recommended various adjustments to the Company's position consistent with their positions on UPIS, discussed supra, and depreciation. The RPA's rate base recommendations on these issues would have the effect of reducing the ADIT to $13,876,000. Staff agreed with the RPA with regard to exclusion of the Enhanced Service Reliability Program, but excluded only Upper Saddle River and Darlington from UPIS and not Oakland as discussed supra. Accordingly, it recommended an ADIT balance of $13,914,000.

The ALJ concluded that his "deduction from rate base would follow that of BPU Staff since it agrees with the same disallowances from rate base." (I.D. at 43).

f) Consolidated Tax Adjustment

In its Initial Brief, Staff maintained that since CEI makes a consolidated tax filing for RECO along with other O&R subsidiaries, if tax savings have been achieved by CEI by offsetting the tax losses of the Company's affiliates with positive taxable income from RECO, these savings should be shared with RECO's ratepayers. (SIB at 64). In its reply brief, Staff further asserted that a consolidated tax savings adjustment reducing rate base by $1,329,000 is appropriate. (Staff's Reply Brief ("SRB") at 13). Staff concluded that this would reduce RECO's revenue requirement by $147,000. While Staff did not explicitly raise this issue during the hearings because it did not have the relevant data at that time, it reserved the right to raise this issue in its Initial Brief. (SIB at 64).

As described above, after receipt of Staff's Initial and Reply Briefs and Staff's motion to supplement the record with certain documents concerning its analysis of the consolidated federal income tax documents, RECO opposed Staff's motion and cross-moved to strike Staff's arguments on this issue from the record. In addition to presenting procedural arguments in opposition to Staff, RECO included in its brief in support of its motion a discussion of its substantive disagreements with Staff's position. RECO argued that: (1) it has had negative taxable income due to its deferred BGS balances; and (2) it has not contributed any income to offset losses from unregulated affiliates on a consolidated basis. (RECO motion to strike, dated April 10, 2003, at 12).

Although on April 17, 2003 the ALJ granted Staff's motion to supplement and denied RECO's cross-motion to strike, in his Initial Decision, the ALJ adopted the position of the Company on this issue and rejected Staff's consolidated income tax adjustment. In support of this ruling, the ALJ cited RECO's assertion that it had negative taxable income due to its deferred BGS balances and that it had not contributed any income to offset losses from unregulated affiliates on a consolidated basis. (I.D. at 55-56).

3. Pro Forma Operating Income

RECO proposed an adjusted pro forma operating income of $10,181,000, and an operating income requirement of $12,042,000. Based upon the updated twelve-month actual data, RECO asserted that it needs $3,156,000 in additional revenues to produce the 9.33% overall rate of return it requested.

The ALJ discussed the following cost items in detail in his Initial Decision:

a) Enhanced Service Reliability

RECO proposed to include estimated Operation and Maintenance ("O&M") expenses of $1,141,000 associated with its Enhanced Service Reliability Programs. These programs include $124,000 for street lighting protection, $550,000 for Tree Trimming Enhancements, $233,000 for pole inspection and treatment, $170,000 for a fault indicator program and $64,000 for transmission line enhancements. (RECO-30; P-2, Schedule 10, 8+4 Update). RECO maintained that these programs will provide customers with "enhanced" service reliability. Company witness Marino asserted that these programs are "over and above RECO's base reliability initiatives" and were designed to improve reliability of service to customers. (RECO-30 at 26-27).

The ALJ adopted the positions of Staff and the RPA that the proposed additional operation and maintenance and depreciation expenses associated with these programs should be disallowed. He concurred with the RPA and Staff that:

> N.J.S.A. 48:2-23 requires the company to provide safe adequate and proper service and to keep its plant in condition to enable it to do so. The enhanced service reliability expense proposed by the company fits into the company's statutory responsibility.
>
> [I.D. at 45].

The ALJ also agreed with Staff's and the RPA's specific recommendations on this issue set forth in Staff's Initial Brief at 51-52, 72-73 and the RPA's Initial Brief at 42-43, 66. I.D. at 50.

b) Pension Expense Adjustment

RECO does not have its own employees. All of the costs associated with employee salaries and benefits are allocated to RECO by O&R. (RECO-30 at 3-4). Thus, the issue of the reasonableness of RECO's allocation of its pension and other post-employment benefits for ratemaking purposes was raised in this case. RECO projected its Statement of Financial Accounting Standards No. 87 ("SFAS 87") pension expense to be $4,199,443 for the 12-months ended July 31, 2004 (15 months beyond the April 30, 2003 test year). RECO reduced this amount by $730,703 for the capitalized portion (17.4%), and by the current net rate pension allowance of $586,626 as authorized by the Board in the Company's last rate case, Docket No. ER91030356J. The current rate allowance is net of the rate reduction ordered by the Board as a result of the electric restructuring proceeding. Thus, RECO proposed an increase in its pension expense of $2,882,114. (RECO-11a: Ex.P-2, Sch.8, update 8+4).

As part of the Settlement Agreement in Docket No. ER91030356J, dated January 10, 1992, RECO was allowed to defer the difference between the pension allowance provided in current rates and the corresponding book expense recorded established by SFAS 87. (RECO-22 at 7). The deferred balance resulting from this treatment was projected to show an over-recovery of $1,651,198 as of April 30, 2003, the end of the test year. (RECO-11a: Exhibit P-2, Sch.8, update 8+4). RECO proposed to amortize this over-recovery as a pension credit over three years, by $550,399 annually. This resulted in the net pension expense increase proposed by the Company in the amount of $2,332,000 for the test year. Id.

The ALJ agreed with Staff and the RPA that RECO's proposal to utilize an expense projection extending 15 months beyond the end of the test year is inconsistent with the known and measurable standards set forth in the Board's Order in the Elizabethtown case, supra, and as such, violates the integrity of the test year concept. (I.D. at 46). The RPA also noted that RECO's projected pension expense would not be verifiable by the end of this proceeding, since its final actuary report for 2004 will not be available until the second quarter of 2004.

Consistent with his position on other decided issues, the ALJ adopted Staff's recommended four-year amortization for the offset to the pension expense associated with the over-recovery balance discussed above. (I.D. at 46).

c) Rate Case Expenses

RECO requested $450,000 for rate case expenses, including legal, consulting and other expenses related to this proceeding. RECO asserted that it was entitled to recover the entire $450,000, rather than sharing the expense 50/50 with ratepayers pursuant to well-established Board policy, because, in this case, the Board directed the Company to file the rate case petition. It therefore argued that these rate case expenses were imposed upon it by the Board.

The RPA, relying on Board policy, and specifically citing I/M/O Elizabethtown Water Company, 62 P.U.R.4th 613 (1984); I/M/O Pennsgrove Water Supply Company, BPU Docket No. WR98030147, dated June 24, 1999; and I/M/O Environmental Disposal Company, BPU Docket No. WR99040249, dated June 14, 2000, aff'd No. A-286-00T3, A-1590-00T3 (App. Div. April 3, 2002), argued that the rate case expenses should be shared 50/50 between ratepayers and shareholders. (RPA Initial Brief at 66). Staff concurred with the RPA and cited I/M/O the Petition of Jersey Central Power and Light Company for Approval of Increased Base Tariff Rates and Changes for Electric Service and Other Tariff Revisions, BPU Docket No. ER91121820J, dated June 15, 1993, as further support for a 50/50 sharing of rate case expenses.

The ALJ adopted the positions of Staff and the RPA and concluded that even though the Board ordered RECO to file a base rate case, the rate case expenses should be shared 50/50 because of potential benefits to both sides. (I.D. at 47). The ALJ also adopted Staff's four-year amortization schedule for rate case expenses. Id.

d) Storm Damage Reserve Expense

The parties all agreed that it would be appropriate for RECO to establish a $763,000 storm damage reserve to provide for a levelized recovery of extraordinary storm costs. Staff recommended a 4-year amortization resulting in $187,500 per year for four years. The ALJ concluded that Staff's recommendation of a 4-year amortization would satisfy the requirements for a storm damage reserve. (I.D. at 47).

e) Depreciation Expense

Based upon the results of its depreciation study and plant balances as of December 31, 2001, RECO recalculated its annual depreciation to be $4,629,000, including $896,000 for negative net salvage. (Staff Exhibit S-9). The Company's proposed depreciation rates from the study result in a depreciation expense of $4,757,000 for projected test year plant. Id.

Both Staff and the RPA noted that RECO provided no documented statistical support for its proposed level of removal costs. Although they did not oppose RECO's service life proposals, they disagreed with the Company's net salvage proposals. RPA witness Majoros testified that based upon a five-year average through December 31, 2001, negative net salvage averaged $43,000 per year. (R-36, Sch. III-2, p.1). The RPA recommended that this representative amount be recoverable from ratepayers. The RPA's annualization of depreciation expense based on plant in service of $174,700,000 as of the end of the test year results in an expense of $3,864,000.

Staff concurred, in part, with the RPA by supporting "unbundled" depreciation rates, i.e. rates that exclude embedded cost of removal provisions. However, Staff recommended a cost of removal expense provision based upon a broader 10-year window of actual experience, rather than the five-year average advocated by the RPA. Based upon the data supplied, Staff recommended a $150,000 annual negative net salvage provision. Staff's annualization of depreciation expense based on plant in service of $174.7 million as of the end of the test year results in an expense of $3,971,000.

The ALJ concluded that Staff's recommendations concerning test-year depreciation expense were reasonable and should be adopted. (I.D. at 47-49).

f) Shareholder 25% Merger Savings

RECO proposed to continue to retain for its shareholders 25% of the merger savings identified by the Board in I/M/O Consideration of the Joint Petition of Orange and Rockland Utilities, Inc. for Approval of the Agreement and Plan of Merger and Transfer of Control, BPU Docket No. EM98070433 ("Merger Order"). The Merger Order permitted a sharing of net merger savings on a 75/25 customer/shareholder basis. To reflect continued pass-through of 25% of the merger savings to shareholders, RECO increased its O&M expense request by $665,000. (RECO-30 at 30).

The RPA and Staff opposed this adjustment. They argued that proper ratemaking requires that utility rates be set based on the appropriate cost of service for a utility and that RECO's cost of service should not be artificially increased for expenses that do not exist. RPA witness Henkes further noted that the combined $200 million premium received by shareholders as a result of the O&R merger with Con-Ed as well as the four years of merger savings already received, a total cumulative amount of $2.7 million, should be sufficient shareholder compensation. (R-50 at 48-49). Staff further noted that increasing the cost of service for artificial costs "surely does not meet the long standing 'known and measurable' standard used by the Board." (SIB at 77).

The ALJ concluded that to continue the annual $665,000 in merger expense would result in overcharges to the customers. He noted that RECO has already recovered $1,995,000 for this expense, and found that RECO's proposal fails to meet the "known and measurable" test as suggested by Staff. (I.D. at 49).

g) Post-Retirement Expenses Other than Pensions

The ALJ adopted the positions of Staff and the RPA and eliminated expense projections included by RECO that extend 15 months beyond the test year. He further adopted Staff's four-year amortization schedule. (I.D. at 50).

4. Summary of Base Rate Findings

In summary, the ALJ found "the rate base calculated by RECO . . . to be excessive and the rate base calculated by the Ratepayer Advocate . . . to be inadequate." (I.D. at 50). He concluded that Staff's rate base recommendation in the sum of $109,420,000 was reasonable and adopted that amount. Id. However, he adopted the Company's request for a 12% return on equity and a 9.43% overall rate of return. As a result, he found a negative operating income deficiency of ($1,282,000), and a negative revenue requirement of ($2,174,000). These findings were based on "8+4" data and did not reflect any of the updated data for the actual "12+0" test year period, which was filed after the close of the record at the OAL and the submission of briefs by the parties. As noted on the chart above, the equivalent "12+0" numbers are a negative operating deficiency of ($2,021,000), and a negative revenue requirement of ($3,423,000).

5. Rate Design

While RECO submitted a cost of service study, it did not use the results of the study to develop its rate design. While the RPA and Staff expressed significant concerns about the methods used in RECO's cost of service study, alleging that it yielded results that are improperly skewed in favor of larger customers, they agreed with RECO's decision to allocate rates on an across-the-board basis. The ALJ adopted this methodology. (I.D. at 55).

With respect to customer charges, bad check charges and reconnection charges, since the Initial Decision resulted in a rate reduction, the ALJ recommended that no change be made in these charges. (I.D. at 55).

IV. EXCEPTIONS AND REPLY EXCEPTIONS

As summarized below, the parties filed Exceptions and Reply Exceptions to the I.D., which largely reiterated the positions advocated during the hearings.

RECO

In its Exceptions and Reply Exceptions, RECO challenged several of the findings in the Initial Decision.

With respect to the deferred balances case, RECO alleges that the ALJ improperly modified the prudence standard by accepting the hindsight calculations of the Auditors regarding the economic impact of RECO's failure to enter into longer term parting contracts with Mirant, the purchaser of O&R's generating facilities. It contends that only through hindsight can the Company's actions be deemed imprudent. (RECO Exceptions at 12-19). In addition, RECO asserts that it was improper for the ALJ to rely upon the Auditors' observation that other New York electric utilities were able to negotiate longer term parting transition power agreements. (I.D. at 19).

RECO further asserts that the ALJ improperly adopted the Auditors' finding that RECO would not have incurred $11,594,000 of hedging costs during the period August 1, 1999 through July 31, 2002 if RECO had entered into a longer term TPSA. The Company contends that this constitutes an "after the fact perspective . . . inappropriate for prudence determinations." (I.D. at 23).

RECO supports the ALJ's conclusions that allow the Company to recover internal labor and overhead costs relating to the PJM transfer and CEP costs. (I.D. at 24-25).

Although as discussed above, the Company takes exception to the ALJ's conclusions regarding the recoverable amount of RECO's deferred BGS balance, it also contends that even assuming it agreed with the ALJ, the ALJ inadvertently understated the interest due on the deferral balance. (I.D. at 25-26). Specifically, RECO asserts that the ALJ inadvertently calculated the interest based on a BGS deferral balance calculated by Staff that reflected several proposed disallowances by Staff that he specifically rejected. Thus, the BGS deferral balance improperly reflected a disallowance of $2.213 million for not completing the PJM transfer a few months earlier, $804,000 for loop flows and $325,000 for the labor and overheads relating to the PJM transfer. All of these disallowances recommended by Staff were, in fact, rejected by the ALJ. Therefore, RECO contends it is entitled to interest in the amount of $7,632,000, rather than $7,417,000 on the ALJ's recommended BGS deferral balance of $77,233,000. Id.

As to post-Transition Period adjustments, RECO takes exception to the ALJ's rejection of its proposal to allocate $3.7 million of the over-recovered ECA deferred balance to cover an anticipated future shortfall, and to allocate $1.7 million of the ECA over-collection to the SBC deferred balance to reduce the under-recovery. It contends that adoption of the ALJ's findings will eventually result in an increase in the ECA rate and the SBC. (I.D. at 30-31).

Finally, with respect to the Temporary Credit, RECO takes exception to the ALJ's rejection of its proposal to offset the excess temporary credit refund with an equal amount of the ECA over-collection. (I.D. at 32).

With respect to the base rate case, RECO supports both the return on equity and overall rate of return recommended in the Initial Decision, and urges the Board to approve the ALJ's findings on this issue. (I.D. at 34).

With regard to rate base issues, RECO supports the ALJ's: (1) inclusion of the Oakland Substation project in rate base; (2) inclusion of the Hourly Energy Pricing ("HEP") billing modification in rate base; and (3) rejection of the consolidated tax savings adjustment proposed in Staff's reply brief. (I.D. at 38). However, the Company takes exception to many of the ALJ's rate base determinations, including, among others: (1) exclusion of the Upper Saddle River and Darlington Substation projects from rate base; (2) exclusion of the Incremental Service Reliability projects from rate base; (3) exclusion of deferred items (e.g. taxes) from the CWC allowance; (4) exclusion of the unamortized deferred expenses (i.e. Ramapo excess tax refund, various BPU Audit costs and R&D costs); (5) application of a four-year amortization period to the rate base adjustments for return of Pension/OPEB over-recoveries and Storm Damage Reserve accrual; and (6) adjustment of ADIT. (I.D. at 40-68).

Concerning operating income, RECO takes exception to the ALJ's adoption of an overall pro forma test year operating income of $11,600,000 proposed by Staff rather than the $8,528,000 it requested (based on 8+4 numbers). Specifically, RECO takes exception to the individual expense disallowances producing Staff's increase of $3,073,000 in pro forma operating income. (I.D. at 68). RECO urges the Board to correct the ALJ's alleged errors and to find a test year operating income of $10,181,000, based on 12-months of actual data. It further urges the Board to approve $3,156,000 in additional revenues or a 2.3% revenue increase in order to produce RECO's 9.33% rate of return (as recommended by the ALJ) on its updated rate base of $129.092 million.

RECO takes exception to several of the ALJ's findings with respect to operating income. It reiterates its arguments for inclusion in operating income of: (1) $1,141,000 in O&M expenses related to the Reliability Programs (I.D. at 68-69); (2) a three-year amortization of OPEBs and Storm Damage Reserve Expense, instead of the four-year amortization recommended by Staff and adopted by the ALJ; (3) the full $450,000 in rate case expenses amortized over three years (I.D. at 69-72); (4) net negative salvage (including cost of removal) recovery the ALJ disallowed from depreciation rates (I.D. at 72-80); (5) the depreciation rates established in RECO witness Hutcheson's testimony (I.D..); (6) $665,000 related to continued sharing of 25% of the savings from the merger of O&R and Con-Ed (I.D. at 80-83); (7) a three-year amortization of all of RECO's deferred expenses related to BPU audits and the Ramapo property tax excess refund (I.D. at 83); (8) $421,000 related to incentive compensation (I.D. at 84-86); (9) continued deferral treatment for pensions and OPEBs (I.D. at 86-87); (10) $225,000 related to common expense allocations and based upon RECO's 12+0 filing (I.D. at 87-89); and (11) monies related to executive compensation and benefits (I.D. at 89-90).

With respect to rate design, RECO notes that the parties are in accord regarding overall rate design, but differ with respect to several customer charges. Specifically, the parties agree that any incremental revenue requirement determined in this case should be applied on a uniform percentage basis across all customer classes, to all rates other than customer charges. RECO takes exception to the ALJ's finding that no change in the customer charge is warranted. The Company also takes exception to the ALJ's decision to disallow any changes related to bad check charges, service reconnection charges, service extension charges and late-payment charges. (I.D. at 91-98).

RPA

In its Exceptions filed in the deferred balances case, the RPA takes exception to the ALJ's BGS deferral determinations and urges the Board to find that RECO's failure to prudently move from the NYISO to the PJM ISO to avoid excess BGS costs was imprudent requiring a $45,379,000 reduction to the BGS deferred balance. (RPA Exceptions at 18-30). In addition, the RPA reiterates its position that once RECO made the imprudent decision to stay in the NYISO, the Company failed to discharge its obligation to mitigate the high cost of NYISO prices with reasonable parting contracts. In particular, the RPA reiterates its criticism of the Company's failure to negotiate a multi-year parting contract with Mirant. (I.D. at 31-33). Finally, the RPA takes exception to the ALJ's determination that RECO's CEP costs were prudent. It urges the Board to find that the CEP costs incurred by RECO during the first three years of the Transition Period should not be recovered through the SBC because RECO failed to meet the "reasonable and prudent" standard for these costs. (I.D. at 34-42).

In its exceptions filed in the base rate case, the RPA takes exception to the ALJ's adoption of RECO's requested 12% return on equity. (RPA Base Rate Exceptions at 12-16). With respect to rate base, the RPA agrees with many of the findings of the ALJ, but takes exception to: 1) the inclusion of the Oakland project (I.D. at 17-20); 2) the inclusion of portions of the 1993 Management Audit Costs and Electric Service Reliability costs (I.D. at 20-21); 3) the length of the amortization period for pensions and OPEBs (I.D. at 21); and 4) the amount of ADIT to be deducted from rate base (I.D. at 22).

The RPA takes exception to some of the ALJ's operating income adjustments, including the amortization period for pension expense adjustments, rate case expenses and storm damage expense (I.D. at 23-25). The RPA urges the Board to adopt a five-year amortization schedule.

The RPA notes that the ALJ appears to have overlooked various issues related to the rate case and argues that these issues should be decided in favor of the RPA. These include: 1) other operating income adjustments (I.D. at 25-26); 2) the miscellaneous operation and maintenance expense adjustment (I.D. at 26-27); 3) the Management Incentive Compensation adjustment (I.D. at 27-28); 4) the telephone line maintenance adjustment and the customer deposit interest adjustment (I.D. at 28-29), and 5) the common expense allocation change adjustment (I.D. at 30).

With respect to the cost of service study methodology, the RPA notes that the ALJ did not rule on this issue. The RPA reiterates its position with respect to cost of service. (I.D. at 32-34). The RPA further urges the Board to adopt its position on dishonored checks (I.D. at 34-37) and reconnection charges (I.D. at 37-40).

STAFF

In its Exceptions to the Initial Decision filed on June 30, 2003, Staff excepted to the ALJ's rejection of Staff's consolidated tax adjustment, pointing out that in accepting the Company's argument that RECO had negative taxable income due to its deferred BGS costs, and therefore had no taxable income that could be utilized to offset losses from unregulated affiliates on a consolidated basis, the ALJ failed to consider the years in Staff's analysis prior to the year 2000. During the period from 1991 through 1999, RECO clearly had positive taxable income, and thus was able to provide tax savings that should be shared by RECO's customers, notwithstanding the parent company's merger with CEI in July 1999.

In excepting to the ALJ's findings on rate of return, including Staff's recommended rate of return on common equity of 9.5%, Staff again stressed the substantially reduced risk the Company now enjoys as a pure distribution company, as opposed to having been an integrated supplier prior to restructuring, as well as the current very low interest and inflation rate environment. Moreover, the Board is now legislatively permitted to approve securitization of prudently-incurred eligible deferred balances to mitigate the impact of deferral recovery on RECO's rates and creditworthiness. Finally, Staff excepted to the ALJ's rejection of BGS disallowances proposed by Staff aggregating $3.342 million (the PJM delay adjustment of $2.213 million, the PJM "loop flow" adjustment of $0.804 million, and internal BGS auction and PJM transfer costs of $0.325 million not shown to be incremental).

In its Reply to the Exceptions of the other parties filed on July 3, 2003, Staff pointed out the need for the Company to update its deferred balances filing to reflect additional actual data beyond November 2002, the last month of actual data reflected in the Company's update filed on December 31, 2002.[8] In excepting to the Company's contention that Staff relied on energy pricing assumptions made by Synapse in recommending its proposed parting contract disallowance, Staff noted that the Company's witness Holtman was actually the source of the pricing assumption at issue. Staff also refuted the Company's contention that Staff's recommended hedging disallowance lacked record support, noting that the Company's results, including hedges entered into at prices as high as $164 per Mwh, spoke for themselves. With respect to Staff's proposed BGS disallowances, Staff agreed with RECO that the ALJ had failed to re-calculate the interest associated with the disallowances.

V. DISCUSSION AND FINDINGS

As described in detail above, these matters have come before the Board as a result of the requirements of EDECA and the Board Orders implementing EDECA. In particular, EDECA required that as of August 1, 1999, each electric utility provide Basic Generation Service, at rates approved by the Board, to customers who did not choose an alternate power supplier, and further provided that these utilities would be permitted to recover on a full and timely basis all reasonable and prudently incurred costs incurred in the provision of BGS, subject to the provisions of EDECA. N.J.S.A. 48:3-57.e. The

[8] The requested update was filed by the Company on that same date (July 3, 2003).

Act also provided that the BPU could devise an “alternate accounting or cost recovery process” to enable the utilities to provide BGS to customers and at the same time sustain the rate reductions mandated pursuant to EDECA during the Transition Period. N.J.S.A. 48:3-57.b.(3).

Pursuant to these and other relevant provisions of EDECA, the Board issued its Summary and Final Restructuring Orders, whereby RECO was directed, among other things, to implement certain rate reductions during the Transition Period (Final Restructuring Order at 64-65); to implement a non-bypassable Societal Benefits Charge and a non-bypassable Market Transition Charge, both of which would be subject to deferred accounting, with review and true-up at the conclusion of the Transition Period (I.D. at 67-68); and to provide Basic Generation Service at Board-approved rates to customers who did not choose an alternate energy supplier (I.D. at 65-67). The Restructuring Orders recognized that RECO might have to defer recovery of some portion of its BGS costs in order to achieve and/or sustain rate reductions through the end of the Transition Period. Accordingly, the Board, consistent with N.J.S.A. 48:3-57.b.(3) permitted RECO to defer recovery of the net excess amount, which amount, together with interest on the amortized balance thereof (net of tax) was to accumulated in a deferred account, to be carried on RECO’s balance sheet as a regulatory asset or liability. (I.D. at 69). The Board further ordered that this BGS deferred balance would be audited by the Board and that those costs determined to be reasonable and prudent would be recoverable with interest at the end of the Transition Period through a non-bypassable charge in a manner and timeframe to be determined by the Board. Id. The Board further ordered that RECO would be permitted full and timely recovery of its NUG purchased power costs over the life of each such contract and that during the Transition Period it would be permitted to defer and subsequently recover with interest the difference between the actual above market NUG contract costs and actual ECA recoveries. (I.D. at 68-69).

In order to allow for adequate time for the Board to review and reset all unbundled rate components by the end of the Transition Period, the Final Restructuring Order required RECO to make a timely filing as to the proposed level of all unbundled rate components to go into effect August 1, 2003. Specifically, RECO was directed to file a petition with respect to its deferred balance and all rate components other than distribution rates no later than August 30, 2002. RECO was further ordered to file its distribution base rate petition no later than October 1, 2002. The Board indicated that these filings would be transmitted to the OAL and assigned to an ALJ who would oversee both the base rate and deferred balances cases on two separate tracks. The cases would ultimately be consolidated for the issuance of an Initial Decision. Both cases would then be returned to the Board for final consideration and decision on a comprehensive basis before August 1, 2003. (I.D. at 65).

The Board **HEREBY FINDS** that these filing requirements have been met and that the filings submitted and the proceedings conducted by Administrative Law Judge William Gural were thorough and complete and provide an adequate record. The Board acknowledges and appreciates the efforts of ALJ Gural in presiding over this consolidated proceeding and in producing a detailed and thorough Initial Decision.

Based on its review of the extensive record in this consolidated proceeding, which has been summarized hereinabove, the Board has determined that the Initial Decision, subject to certain modifications, which will be set forth and discussed herein, represents an appropriate resolution of these matters. Accordingly, the Board **HEREBY MODIFIES** the Initial Decision as described below.

A. Deferred Balances Case

1) BGS Deferral

a) Standard of Review

Pursuant to its statutory mandate, the BPU is required to ensure that public utilities provide New Jersey consumers with safe, adequate and proper service at just and reasonable rates. N.J.S.A. 48:2-21; N.J.S.A. 48:2-23. Consistent with long established and well-settled principles of law, the utility in a rate proceeding must bear the burden of proof with respect to all elements of its expenses, which it seeks to pass through in rates to its customers. In re Public Service Electric and Gas Co. 304 N.J. Super 247 (App. Div. 1997), cert. den. 152 NJ 12; Public Service Coordinated Transport v. State 5 NJ 196 (1950).

In implementing EDECA, the Legislature declared numerous policy goals related to the need to lower the high cost of energy, ensure universal access to affordable and reliable electric power service, and the provision of a smooth transition from a regulated to a competitive supply power market place, including provisions which afford fair treatment to all stakeholders during the transition. N.J.S.A. 48:3-50 a (12).

In particular, the Legislature declared that it was in the public interest to:

> Provide each electric public utility the opportunity to recover above-market generation and supply costs and other reasonably incurred costs associated with the restructuring of the electric industry in New Jersey, the level of which will be determined by the Board of Public Utilities to the extent necessary to maintain the financial integrity of the electric public utility through the transition to competition, subject to the achievement of the other goals and provisions of this act, and subject to the public utility having taken and continuing to take all reasonably available steps to mitigate the magnitude of its above-market electric power generation and supply costs;
>
> [N.J.S.A. 48:3-50.c.(4)]

N.J.S.A. 48:3-57 provides, among other things, that power procured for BGS shall be purchased at prices consistent with market conditions, and that utilities shall be permitted to recover on a full and timely basis “all reasonable and prudently incurred costs incurred in the provision of basic generation services...” N.J.S.A. 48:3-57.e.

As noted above, on July 31, 2002, Governor McGreevey signed Executive Order No. 25, creating the Deferred Balances Task Force, which was charged with examining the deferred balances that electric utility companies have accumulated and to provide a report addressing the reasons why the deferred balances were accumulated, what mitigation steps were taken by utilities to reduce the deferred balances and how they ought to be addressed to best protect the interest of ratepayers. In its final report, the Task Force noted that the BPU was conducting full evidentiary hearings on this issue, with participation by the RPA and other interested parties, as well as including an independent audit of the deferred balances. The Task Force strongly supported consumer protections to ensure that the burden of proof for recovering the deferred balances is placed squarely on the utility companies. The Task Force also urged that strict scrutiny be applied to utilities' claims of deferred balances.

Thus, in performing its prudence review of the deferred BGS balance, the Board is cognizant of its difficult responsibility to balance the competing interests and will apply strict scrutiny to assess whether utility management made proper decisions and took proper actions that a reasonable company should have made and taken, given the alternatives and information available at the time the decisions and actions were taken, consistent with the applicable legislative and other regulatory requirements. Consistent with well-established principles of law, the Company must bear the burden of proof to demonstrate the prudence of its actions and decisions.

b) The PJM Transfer Issue

In finding that RECO was not imprudent in the timing of the transfer of its Eastern Division from the NYISO to the PJM ISO, and thus that the BGS disallowances proposed by the RPA and Staff should be rejected, the ALJ cited such factors as: (1) uncertainty over energy pricing during the Transition Period; and (2) uncertainty over the outcome of the application for the transfer, given that such a transfer had never before been approved by the FERC and was opposed by PSE&G. (I.D. at 21-22). The ALJ cited RECO's testimony claiming that it was not apparent at the time the RPA asserted the transfer should have occurred (August 1, 1999) that PJM would be a lower cost alternative to the NYISO. In fact, RECO claimed that the parties in its restructuring proceedings expected lower prices to prevail in the NYISO. The ALJ thus concluded that: "[i]t is for this very reason that no party at that time (not the New York Public Service Commission, not the Public Utility Law Project, not the [B]oard, and not the Ratepayer Advocate) proposed or supported the RECO Transfer." (I.D. at 20-21). The ALJ also noted that the Auditors did not find the timing of the transfer unreasonable. Id.

While the Board agrees with the ALJ that the RPA's recommendation on this issue is overly harsh and should be rejected, the majority of the Board disagrees with the Initial Decision with respect to the ALJ's rejection of Staff's proposed $2.2 million disallowance.[9] In view of the financial magnitude of the transfer issue, particularly

[9] Commissioners Alter and Murphy dissented on the PJM Transfer issue and would have affirmed the findings of the ALJ on this limited issue. They expressed serious concern with the disallowance of $2,200,000 for "PJM Transfer Delay". Although not recognized by the ALJ, Board Staff saw this as

when all the related adjustments are taken into account, the Board has given the record on this issue particular scrutiny, as discussed in detail herein.

As indicated above, the RPA maintains that RECO should have transferred its Eastern Division, which serves approximately 90% of its load, from the control of the NYISO to the PJM ISO by August 1, 1999, the beginning of the Transition Period, as compared to the actual transfer date of March 1, 2002. In an update of his Direct Testimony distributed at the February 19th hearing (R-6), RPA witness Cotton proposed a reduction in RECO's deferred BGS balance of $32.891 million, including interest of $4.546 million, assertedly representing the estimated increase in the cost of RECO's energy and capacity purchases and related interest incurred as a result of the delay. He further asserted that if RECO had joined PJM by August 1999, it would not have been able to share in the energy and capacity obtained under parting contracts that O&R entered into with Mirant,[10] since these contracts required all transactions to occur within the NYISO. (R-4 at 35). Similarly, in witness Cotton's opinion, the hedging contracts that the Con-Ed Electricity Supply Department executed in 2000 and 2001 on RECO's behalf would not have been necessary if RECO had joined PJM by August 1999. He accordingly proposed making additional adjustments to RECO's BGS deferred balance of $1.123 million associated with the TPSA/IESA contracts (including interest of $0.174 million), and $11.275 million for the assertedly unneeded hedging contracts (including interest of $0.921 million), bringing his total recommended adjustment related to the PJM transfer issue to $45.289 million.[11]

Witness Cotton further asserted that RECO's apparent reason for seeking membership in PJM was to participate in the statewide BGS auction to secure BGS supply for the state's four electric utilities for the last year of the Transition Period. Thus, he argued, the March 2002,[12] transfer occurred much later than it should have. Other reasons cited in support of his adjustment include: (1) the substantially lower cost of PJM energy purchases relative to those from the NYISO, a difference he maintained was evident as early as 1999; (2) the fact that as early as 1997 RECO knew that its parent company

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necessary to recognize that the transfer could have been accomplished six months earlier than it occurred. Commissioners Alter and Murphy believe that, given the record presented on this issue, RECO's business decision should not be reviewed retrospectively absent imprudence or negligence; neither of which, in their view, were adequately demonstrated here.

[10] A Transition Power Sales Agreement executed with Southern Energy Affiliates on November 24, 1998, which provided the O&R system with 940 Mw of capacity through April 30, 2000 and 600 Mw through October 31, 2000, as well as 416-500Gwh of on-peak energy from November 1, 1999 through April 30, 2000 and 100-131 Gwh of off-peak energy during that same period. Additional energy up to the full requirement of O&R's system was supplied under another agreement, the Incremental Energy Sales Agreement executed with three affiliates of Southern Energy Affiliates on June 14, 1999. The IESA was in effect from June 30, 1999 through November 18, 1999, the date the NYISO began operation as an ISO. (RECO witness Joseph A. Holtman's Direct Testimony (RECO-4) at 13, 15).

[11] The individual adjustments were derived by successively taking the differences between the BGS amounts shown on line 1 on page 1 of Schedules JDC-1 through 4 of R-6.

[12] Although the auction was held in February 2002 and the transfer did. not take place until March 1, 2002, RECO did. in fact participate in the auction as a PJM member.

planned to divest its generating units, and thus should have started its PJM investigation at that time; (3) RECO's mounting BGS deferral in the first year of the Transition Period, which should have alerted it to the need to reduce the cost of its BGS supply; and (4) the failure of retail choice to develop in RECO's service territory, which should have led it to realize it would need to provide BGS for some time to come. It was not until June 2001 that RECO performed an economic study of the costs and benefits of the transfer, which by then showed millions of dollars of savings. (R-4 at 23-26).

Witness Cotton asserted that, compared to the NYISO, PJM was quicker to develop as an ISO, implementing as it did the nation's first bid-based energy market in April 1997, and enrolling 100 members by the end of that year, a level only approached by the NYISO some two years later after beginning operation as an ISO on November 18, 1999. Moreover, studies quoted by witness Cotton indicated that the NYISO failed to achieve the reduction in energy prices anticipated to result from the competitive wholesale market, and by the summer of the year 2000, tight supplies and systems that did not work as planned led to double digit rate increases for some New York consumers, i.e., in New York City. (I.D. at 28-31).

As to RECO's reasons for not attempting to join PJM sooner, witness Cotton disputed RECO's claim that the transfer would entail significant costs, maintaining that such costs were, at most, the $1.143 million claimed in witness Marino's Exhibit FPM-2, and could be as low as $0.668 million, which the RPA's witness considered to be a very small price to pay to achieve estimated savings of $28 million over a 2½ year period (from August 1999 through February 2002). Moreover, he pointed to the more advanced development of PJM relative to the NYISO, and predicted tighter capacity supplies in the North American Reliability Council Region, of which New York is a part, relative to the MI.D.-Atlantic region as reasons for believing NYISO prices would be higher than PJM's, contrary to the Company's assertion that there was no reasonable basis for making this assumption at the time. (I.D. at 31 to 34).

Additionally, RPA witness Chernick, in oral surrebuttal testimony, contended that the Auditors, by accepting RECO's inaction until the evidence favoring the transfer was overwhelming, applied the wrong standard of review. (4T at 63). He asserted that there was a long history of favorable PJM prices relative to those of the power pools of the Northeast, reflecting, for example, the greater proportion of coal and nuclear capacity in PJM and other factors. Moreover, going forward, substantially more capacity was expected to come on line in PJM, further reinforcing the RPA's contention that RECO should have begun its transfer investigation sooner than it did. (I.D. at 71-75). Witness Chernick further asserted that the Auditors (and RECO) put too much emphasis on the volatility of the PJM capacity market during the summer of 2000 (which, as he put it, turned out to be a "transitory blip") as a reason for waiting. (I.D. at 76-78).

In defending the timeliness of RECO's PJM transfer, Company witness Holtman pointed to the Company's need to first perform the necessary analysis in recognition of the immaturity of both ISOs, as well as other potential regulatory developments under consideration by the FERC at the time. He asserted that a meaningful comparison of the economics of the two ISOs could only be performed after the accumulation of data over a reasonable period of operation. He noted that the Auditors had found that the Company had acted appropriately in first gathering and analyzing pricing data before moving forward with the transfer. (RECO-5 at 1-5).

The Board has also carefully reviewed the opinions expressed by the Auditors. After setting forth and reviewing a very detailed chronology of the major events leading up to the March 1, 2002 transfer, the Auditors concluded that the transfer was “undoubtedly a good idea,” but did not find RECO’s timing unreasonable or imprudent. (S-8 at 56). In assessing the timeliness of the transfer, the chronology was broken down into the following sub-periods:

1. November 1999, following the commercial operation of the NYISO, through August 2000, in which data was accumulated that showed NYISO prices were higher than PJM’s from the outset;

2. September 2000 through November 2000, during which Con-Ed’s Supply Department investigated the economic and other aspects of the transfer, and concluded that it was likely to be economic;

3. December 2000 to May 2001, during which preliminary discussions and meetings with PJM and the NYISO took place;

4. June and July 2001, during which PJM was formally notified that O&R wanted to proceed with the transfer, and initial steps were taken to install the required equipment. An October 1, 2001 target date for joining was set;

5. August and September 2001, during which objections by PSE&G and the September 11th terrorist attack delayed PJM’s decision;

6. October through December 2001, during which the approval process was completed. After PJM’s approval on October 1, 2001, PJM and RECO jointly petitioned FERC for approval, which was granted on December 21, 2001;

7. January and February 2002, when the final implementation steps (installing of metering and other equipment) were taken, culminating in the transfer on March 1, 2002.

While generally concurring with the Auditor’s review, Staff questioned the two months it took the Company to install the necessary metering and communication equipment following the FERC approval, maintaining it was unduly long. In addition, Staff maintained that sub-periods 1-3 above could have been collectively shortened by several months. Thus, Staff concluded that the transfer could reasonably have been accomplished six months earlier than it occurred, and recommended a corresponding disallowance of $2.2 million.

Having carefully considered the positions of all parties, the Board does not believe the full amount of the RPA’s recommended disallowances would be fair or appropriate.

The Board agrees with the ALJ that the preponderance of the evidence does not support the magnitude of the imprudence disallowance proposed by the RPA. However, the majority of the Board believes that the RPA and Staff have raised significant concerns, supported by sufficient credible evidence to justify a finding that RECO's business judgment on this issue was not as prudent as it should have been, thereby meriting some level of disallowance. Specifically, we concur with Staff in questioning the extra two months it took the Company to install the necessary metering and communication equipment following the FERC's approval of the transfer from NYISO to PJM (RECO-4 at 22).

The majority of the Board accepts as reasonable Staff's contention that it took the Company far too long to install the necessary metering equipment following the FERC's approval of the transfer, particularly in view of what appears to be the relatively simple nature of the project -- a project so straightforward, in fact, that it is difficult to understand why it took two months to complete even after the Company received FERC approval. Moreover, Staff maintains that installation of this equipment could have and should have been pursued concurrently with the FERC proceeding. This position is further supported by the fact that FERC appears to have resolved ACE's petition within a relatively short period of time. In its brief, Staff refers to this action by FERC as creating a strong presumption that FERC "fast-tracked" its approval of the transfer process in order to allow RECO to participate in New Jersey's February 2002 statewide BGS auction as a PJM member. As the provider of last resort to BGS customers who did not and by and large had little opportunity to choose an alternate energy provider, the utility had a duty to ratepayers to procure power at just and reasonable prices consistent with market conditions. In the majority's view, sound business judgment warranted a greater degree of forward thinking and anticipation by RECO in view of the situation and the likelihood that it would receive the necessary approval, so that customers could receive the benefits of the lower rates available on the PJM system sooner rather than later.

Moreover, the record also supports a conclusion that there was what, at best, could be described as a lack of urgency by RECO at the beginning of the Company's transfer process. Although all of the steps taken beginning in and continuing after sub-period 4 of the time intervals considered by the Auditors appear to have proceeded as expeditiously as could reasonably be expected, and while the Company's performance in prosecuting its petition before the FERC, once filed, appears to have been diligent, the evidence supports a finding that in the sub-periods prior to June 2001, the Company did not pursue the PJM transfer as expeditiously as it should have given the reasonably anticipated cost savings. Staff maintains that sub-periods 1 through 3 could have been collectively shortened by several months in view of the size of the favorable PJM price differentials shown in Appendix D of R-4, i.e., an average differential of approximately $16 per Mwh as compared to NYISO prices in the year 2000 and $10 per Mwh in the first 5 months of 2001, as well as projected savings in the years 2001, 2002 and 2003 of $12.9, $21.4 and $25.0 million, respectively, if the Eastern Division's load were to be served by PJM in those years. Although Staff agreed that it would be unrealistic to expect that RECO could have (or even should have) effected the transfer as early as August 1999, Staff concludes that the transfer could well have been accomplished 6 months sooner than it actually was, and recommended a disallowance of $2.2 million of deferred BGS costs based on the quantification of the impact of the delay determined in Appendix F of R-4.

As shown by the data in Appendix D of R-4, by June 2000, it was abundantly clear that PJM's energy prices were well below NYISO's, as evidenced by the difference of $36 per Mwh in that month alone. Given this compelling difference, in our view the deliberations that took place in sub-periods 1 and 2 above, and extending into sub-period 3, should have proceeded much more expeditiously, and thus we find the four-month delay estimated by Staff to have been both avoidable and conservative.

Taken together, the delay in the installation of necessary equipment subsequent to FERC approval and the inefficient pursuit of the PJM transfer early on in the process although not supporting the significant disallowance argued for by the RPA, clearly support the disallowance recommended by Staff. Accordingly, we **HEREBY ADOPT** Staff's recommended BGS disallowance of $2.213 million as the cost of this delay.

c) Parting Contracts

Although there is a slight ambiguity with respect to the Initial Decision's finding on this issue,[13] it appears that, after considering the position of the parties, the ALJ agreed with Staff's disallowance of $8.2 million of RECO's deferred BGS costs to reflect the failure of RECO's parent Company to extend the energy component of the TPSAs, as recommended by the Auditors. (I.D. at 23, 29). While the Board concurs with the ALJ's findings, in view of the significance of this issue, the Board believes that some additional discussion is warranted.

As summarized above, after reviewing RECO's spot market and bilateral purchases during the first three years of the Transition Period, the Auditors concluded that the Company (i.e. O&R, RECO's parent company) was imprudent for failing to negotiate a multi-year parting contract with Mirant, the purchaser of O&R's generating units, thus exposing RECO's customers almost completely to the nascent NYISO spot market following the expiration of the TPSA in October 2000. (S-8 at 30). As evidence that such an extended contract could have been secured, the Auditors pointed to several multi-year parting contracts entered into by other New York utilities upon divestiture of their generating units, and their approval by the New York Public Service Commission.

All of the cited utilities assertedly entered into parting contracts in 1998, 1999 and 2000 of at least three years duration, which were approved by the NYPSC, contrary to RECO's assertion that the NYPSC discouraged such contracts for fear that, by locking up supply, they might inhibit the development of a competitive wholesale market. (S-8 at 34-36). Moreover, while some other utilities apparently did not execute similar

[13] At page 29 of the I.D., the ALJ made an explicit finding that both Staff's recommended parting contract disallowance ($8.185 million) and hedging cost disallowance ($5.817 million) should be disallowed in determining the recoverable deferred BGS balance. On page 28, however, only the hedging cost disallowance was deducted. The Board assumes the discrepancy was inadvertent. Moreover, it was not challenged by the Company.

parting contracts with the purchasers of their generating units, they retained significant generating assets that provided a physical hedge against higher market prices. Id.

Additionally, in New Jersey, PSE&G fully met its BGS requirement by entering into a three-year contract priced at the Board-approved rate charged for BGS service, and JCP&L executed parting contracts with the purchaser of its generating units in November 1999 and August 2000 that assertedly extended through March 2003. (I.D. at 38). About 75%, or 1,800 Mw of Atlantic Electric's BGS requirement was also assertedly met by long-term purchased power contracts. Id.

The Auditors further asserted that, not only did RECO fail to obtain a longer-term contract, it did not even quantitatively evaluate the potential costs and benefits of such a contract, opting instead to rely on a business judgment that it could not justify locking in costs that significantly exceeded its retail rate recovery. (I.D. at 39).

The Auditors also found evidence to suggest that Mirant would have been amenable to a parting contract extending more than one year,[14] citing an apparently verbal offer it made in the spring of 1999 to extend the TPSA already in place beyond one year at prices approximately 20% above those of that agreement. In support of this possibility, the Auditors cited several multi-year TPSAs which Mirant executed with other utilities. Nor, in the Auditors' opinion, would a longer contract have necessarily resulted in a lower bid for O&R's divested assets, contrary to RECO's claim. (I.D. at 39-40).

The Auditors agreed with the Company as to the inadvisability of entering into very long-term contracts, maintaining, however, that this did not preclude the use of two to four-year agreements that additionally could have been limited to approximately half of RECO's supply requirements. Moreover, such a contract would have served as a hedge against the price uncertainty cited by RECO, and in particular, the possibility of prices going up as well as down, as evidenced by the bids for energy and capacity the Company received in September 1998, all of which it rejected as being too high. The allusion to NUG contracts, based as they were on forecasts of avoided costs literally decades into the future, was asserted to be far removed from the two to four-year contract alternatives the Auditors believed the Company should have considered, and furthermore, there was no evidence, in their view, to suggest that such limited-term contracts for only a portion of RECO's supply would have inhibited the development of the wholesale energy market, as was argued by the Company. (I.D. at 41-43).

With respect to the risk of customer migration (the risk of holding excess capacity if a longer-term parting contract had been entered into and more customers elected to choose third party suppliers than expected), the Auditors asserted that RECO already knew customer migration most likely would be limited, especially in New Jersey where the shopping credit was relatively low in comparison to elsewhere. Whether the complete lack of migration that actually occurred could have been anticipated or not, the Auditors maintained that a parting contract for only part of the Company's supply

[14] Apparently this was in reference to the energy component of the TPSA, which was effective through April 30, 2000. The capacity component continued through October 31, 2000. (RECO-4 at 15).

requirements could have managed the risk that a significant number of customers would leave for competitive suppliers. (I.D. at 43).

As to the Company's argument that a longer-term parting contract would have reduced the price it received for the divested assets, the Auditors asserted that by assuring the purchaser of at least partial cost recovery that otherwise might be lacking in a competitive market, thereby reducing ownership risk, a parting contract might actually have proven attractive to the purchaser. (I.D. at 44).

Finally, the Auditors maintained that notwithstanding the question as to whether the Company's procurement strategy was appropriate in the context of New York regulation, given the narrow focus of its parting contracts, i.e., that their terms were basically structured to bridge the gap between the time O&R's generating units were divested and the commencement of NYISO operations, they failed to properly provide for RECO's multi-year BGS obligation in New Jersey. (I.D. at 45).

In quantifying the impact of their finding that RECO was imprudent for failing to negotiate a longer-term parting contract, the Auditors assumed that the Company would have been able to execute a three-year TPSA with Mirant for 50% of its requirements through June 2002 at prices about 20% higher than those of the TPSA actually executed (the energy component of which, extended through April 2000). With such a longer-term agreement in place, the Auditors maintained that it would not have been necessary for the Company to place the hedges it did during the period from August 1, 1999 through July 31, 2002. (I.D. at 46).

As shown in Table 11-1 on page 64 of S-8, the Auditors proposed a total recommended disallowance of $26.8 million, comprised of increased energy costs of $25.0 million under the assumption that energy could have been obtained under the extended TPSA at a substantially lower price ($31.20 per Mwh)[15] than that of the equivalent energy purchased from the NYISO, plus avoided hedging costs of $11.6 million, less $9.8 million of capacity payments the Auditors assumed would have been higher under the extended TPSA.

In rebuttal testimony, the Company argued that a longer term parting contract would likely have resulted in a lower bid price for the assets. (RECO-3 at 5). RECO also argued that the cited parting contracts entered into by other utilities in New York and New Jersey were distinguishable (I.D. at 10-17, 20-22), and further argued that TPSAs were assertedly not provided for in O&R's restructuring plan presented to the NYPSC because they would have constrained the development of a wholesale market for electricity. (I.D. at 17-19).

RECO also disputed the Auditors' assertion that a longer term TPSA would have been available to O&R at prices approximately 20% higher than those charged for the first year. (RECO-5 at 3-4). RECO further asserted that at the time the TPSA was entered

[15] $26 per Mwh increased by 20%, as indicated at 6T at 97.

into, there was a general expectation that market energy prices would decline over time, thus supporting a shorter term TPSA. (RECO–8 at 9-10).

As to the issue of whether RECO should have negotiated a longer-term (two to four year) parting contract, Staff disagreed with the position of the Auditors, finding that the desirability of this was not necessarily apparent at the time, since at the time the TPSA was entered into, it was still reasonable to believe that the competitive market place would yield falling prices. However, given Mirant's apparent willingness to discuss a contract extension of a few months, Staff questioned why the energy component of the original agreement terminated in April, before the peak months of July and August, and absent a reasonable explanation from the Company, found that decision to be imprudent. Thus, Staff recommended that the Company's BGS deferred balance be reduced by the $8.185 million of savings that the Auditors' analysis indicated could have been realized if the energy component of the TPSA had continued to be in effect in the months of May through August 2000. (SIB at 26-28).

After carefully reviewing the arguments of the Auditors and the Company on this issue, the Board finds there to be merit on both sides. While the Auditors' review of the parting contracts entered into by a number of other utilities indicates that contracts having terms as long as three years were clearly possible, the Company cites distinguishing factors in support of the terms of the TPSAs it entered into with Mirant, not the least of which was the Board's avowed goal of minimizing stranded costs at that time, and an expectation that the competitive market place, including the NYISO after it became fully operational, would produce lower energy prices, thereby favoring shorter, as opposed to longer contract terms. Moreover, Staff correctly notes that the desirability of three-year contract terms was not necessarily apparent at the time the initial TPSA was signed in November 1998. At that time, before the enactment of EDECA, it was still reasonable for the Company to believe that the competitive market place would likely yield falling prices. Accordingly, the Board **HEREBY FINDS** that RECO, i.e., O&R, the parent company, was not imprudent for failing to negotiate parting contract having terms as long as three years, as the Auditors maintained it should have.

However, the Board concurs with Staff and the ALJ in questioning the shorter term of the energy component of the TPSAs relative to the capacity component. Although the Company maintains that entering into a contract for as long as three years was unacceptable to Mirant and therefore was never discussed, the Board **FINDS** that RECO could and should have explored the possibility of the "few months" extension that the record demonstrates Mirant apparently was willing to entertain. As shown in the Auditors' analysis (Table 11-1 on page 64 of S-8), these months were the months in which the savings from the extension would have been the highest. If, for example, the term of the energy component of the TPSA (which expired in April 2000) had simply matched the term of the capacity component, i.e., if it had extended through October 2000, the Auditors' analysis shows that the savings relative to NYISO purchases would have been $11.3 million for the six-month period from May through October 2000.

Given Mirant's apparent willingness to discuss a contract extension of a few months, it is inexplicable why RECO permitted the energy component of the original agreement to terminate in April, before the peak summer months of July and August. The Board agrees with the ALJ that RECO's actions in this regard were imprudent. In order to account for this imprudence, the ALJ, adopting Staff's recommendation, found that the Company's BGS deferred balance should be reduced by the $8.185 million of savings that the Auditors' analysis indicated could have been realized if the energy component of the TPSA had continued to be in effect in the months of May through August 2000. The Board **HEREBY ADOPTS** the ALJ's ruling on this issue and **FINDS** the Company was imprudent for having failed to extend the energy component of its TPSA with Mirant through the critically important summer months of July and August of 2000, when its own testimony indicates it had the opportunity to do so. Accordingly, it is **HEREBY ORDERED** that $8.185 million of deferred BGS costs be disallowed in accordance with the record provided on this issue and the decision of the ALJ.

d) Hedging Costs

While agreeing with the Auditors that if the Company had entered into an appropriate multi-year parting contract, RECO would not have incurred $11.594 million of hedging costs during the first three years of the Transition Period,[16] the ALJ accepted Staff's more modest recommended disallowance of one-half of the hedging costs, or $5.817 million. (I.D. at 24-25). Staff's recommendation in turn was premised on the results achieved by RECO's (i.e., the Con-Ed Supply Department's) hedging program during the Transition Period, which Staff characterized as being "a failed and costly experiment in which the Company [i.e., its stockholders] should share." (SIB at 34-35). Again in view of the significance of the issue, we believe it warrants the additional discussion below.

The use of hedges as a risk management tool, particularly to protect against spikes in on-peak energy prices, was discussed by witness Holtman in his Direct Testimony. (RECO-4). Obtaining that protection, however, can be costly, as is evident from Exhibit JAH-7 attached to Holtman's testimony, which shows that forward prices were above, and in some instances substantially above, the "settled price" in the delivery month most of the time in 2001 and 2002. Moreover, Con-Ed's experience with the hedges it placed in these years confirms this result, as shown by Exhibit JAH-9. Other than the ratcheting down evident over time, about the only positive commentary on the program in witness Holtman's testimony appears on page 18, where he notes that the Con Edison Supply Department chose not to enter into any hedges in February 2000 at an offered price of $84.50. This, he went on to note, turned out to be a "favorable decision for buyers in southeastern New York." Staff agreed, and faulted the Company for entering into the ill-advised transactions appearing in Exhibit JAH-9, especially in view of witness Krapels testimony, in which he noted that forward prices for peak energy deliverable in July and August of 2000, at $140 per Mwh, commanded a premium on

[16] The RPA's witness made a similar argument, asserting that if RECO's Eastern Division had been transferred to the NYISO by August 1, 1999, as the RPA maintained it should have been, the hedging costs would not been incurred. Thus, the RPA recommended disallowing them as part of its PJM delay disallowance. After including the hedging costs incurred or projected to be incurred in the year ended July 31, 2003, the total hedging costs expected to be incurred during the full four years of the Transition Period was $11.634 million based on the Company's December 2002 update (FPM-2 at 1) and $11.723 million based on the Company's July 2003 update. (RM-2 at 1).

the order of 100% over the settled prices in those months. (RECO-3 at 8-9). While noting that the prudent use of financial instruments had been authorized by the Board, Staff concluded that the results of the Company's hedging program were so unreasonably poor as to be tantamount to a failed and costly experiment in which the Company's shareholders should share. Accordingly, Staff proposed that one half of the $11.594 million of hedging costs incurred by RECO through July 31, 2002 be disallowed. The ALJ agreed with Staff on this issue.

In taking exception to the ALJ's adoption of Staff's recommended disallowance, RECO argued that Staff's recommendation had no basis in the record, and that the record evidence in this proceeding uniformly supported the prudence of RECO's hedging practices. (RECO Exceptions at 21).

In replying to RECO's exception, Staff asserted that it had relied on RECO's own testimony and exhibits in making its recommendation, and in particular, once again referred to Exhibit JAH-9 discussed above. This exhibit shows that in 2001, Con-Ed executed a total of 38 hedges, of which only two turned out to be favorable (hedges contracted at a price less than the settled price): the May 2001 hedges executed with Counterparties C and D on April 25, 2001. The average contract price of these two favorable hedges was $52.5 per Mwh, or about 10% less than the average settled price of $58.4 Mwh. On the other hand, the contract price of the 36 unfavorable hedges – including the July and August 2001 hedges entered into with Counterparty C at the expensive price of $141 and $164 per Mwh, respectively – averaged $84.5 per Mwh, as compared to an average settled price of about $54.1 per Mwh. Not only does this represent an exorbitant premium of over 55%, but, at $84.5 per Mwh, the average contract price was at odds with the Company's rejection of a bid it received for 200 Mw of peak energy during June through September of the previous year at that exact same price. (RECO-4 at 18).

The Board recognizes that, in general, hedges cannot be expected to reduce costs, in that their primary purpose is to protect against extreme prices and volatility, and that a premium must be paid for this protection. However, based on the Board's review of the record, and in particular the listing of the individual hedges executed by the Company contained in Exhibit JAH-9 as compared to the averaged settled prices over the period in question, the Board agrees with Staff that the premiums the Company was willing to pay were clearly excessive and imprudent. When confronted with average monthly prices as high as $164 per Mwh, the Company should have concluded that there was very little chance of its doing worse on a sustained basis by relying on the spot market (the NYISO) instead. In the Board's view, the Company has not provided a satisfactory explanation to explain its poor performance with respect to its hedging practices. The Board finds that the Company has not met its burden of proof to demonstrate the reasonableness of its hedging transactions and accordingly, **HEREBY ADOPTS** the decision of the ALJ to disallow one-half of the hedging costs incurred by RECO during the Transition Period, as recommended by Staff.

e) Other BGS Issues

As discussed above, in accordance with the March 25, 2003 Secretary's Letter, the Initial Decision did not address issues associated with the securitization and/or amortization of RECO's deferred BGS balance, nor did it address the appropriate interest rate to be applied to the Company's post-Transition Period SBC and ECA deferrals. Nevertheless, these issues were discussed by the parties in their filings and will be discussed herein. Additionally, as discussed above, Staff recommended that interim recovery of RECO's deferred BGS balance be determined on a net-of-tax basis. Accordingly, these issues are included below as part of the Board's analysis of the deferred balances case.

1) Recovery of the Deferred BGS Balance on a "Net-of-Tax" Basis

During the first three years of the Transition Period, RECO accrued interest on the aggregate balance of its deferred costs without deducting the related accumulated deferred income taxes from the balance. However, as discussed herein, the record in this proceeding, as well as prior Board decisions, confirm that the BGS deferred balance was supposed to be accruing interest "net-of-tax," i.e., on the balance after deducting the deferred taxes.

In accordance with the Summary Restructuring Order, interest on the first $5 million of the aggregate deferred balance was to be accrued at RECO's cost of seven-year debt, and the balance above $5 million was to be accrued at that rate plus 350 basis points. These rates were to be adjusted on August 1st of each year of the Transition Period. Thus, rates of 7.27% and 10.77% were applied for the year ended July 31, 2000; rates of 7.60% and 11.10% were applied for the year ended July 31, 2001; and rates of 6.32% and 9.82% were applied for the period from August 1, 2001 through July 22, 2002. (RECO-7 at 22-25). The interest was calculated monthly on the beginning and ending average aggregate deferred balances, and compounded annually (added to the balance on which interest is accrued at the beginning of each transitional year).

Pursuant to the July 22, 2002 Final Restructuring Order, the interest rate applicable to RECO's entire deferred balance was prospectively reduced, as of the date of the Order, to the yield on seven-year constant-maturity treasury notes, plus 60 basis points. This modification made RECO's rate for accruing interest on the deferred balances the same as the rate approved by the Board for the state's three other electric utilities. While the Final Restructuring Order left open the possibility of having this rate apply during the first three years of the Transition Period as well, after first affording the parties the opportunity to be heard on the issue upon review of RECO's deferred balances, the Board subsequently issued a further Order in response to a motion for reconsideration and clarification filed by RECO, which clarified that the new rate would apply prospectively only. I/M/O Rockland Electric Company's Rate Unbundling, Stranded Cost and Restructuring Filings, BPU Docket Nos. EO97070464, EO97070465 and EO97070466, Order on Motion for Reconsideration and/or Clarification, dated October 16, 2002 ("October 16th Order").

The Final Restructuring Order provided that interest on RECO's deferred balance was to be accrued net-of-tax, consistent with the language set forth in RECO's proposed Plan for Resolution of Proceedings, which it had filed with the BPU on July 13, 1999, which Plan had been approved, with modifications, by the Board in its Summary and Final Restructuring Orders. In its October 16th Order, the Board reaffirmed that the interest rates in effect during the Transition Period would be applied to the net-of-tax balance of deferred costs.

Pursuant to the October 16th Order, and as part of an updated schedule filed on December 31, 2002 to reflect actual data through November 2002 and other adjustments (RECO-2), RECO revised its interest calculation to accrue interest on a net-of-tax basis during the first three years of the Transition Period. This reduced the total interest projected through July 31, 2003, the end of the Transition Period, by $5.869 million (from $14.787 million as filed to the $8.918 million shown in the update), and the interest on the BGS component of the deferred balance by $6.033 million (from $15.334 million to $9.301 million).[17]

However, RECO did not recalculate its proposed four-year recovery of the BGS deferred balance (the recovery proposed in the absence of securitization) on the same net-of-tax basis. As shown on page 2 of Schedule FPM-1 of RECO-2, the updated BGS deferred balance claimed by RECO, including interest, was $100.536 million. Recovering the full (gross) amount via a level, or mortgage-like payment over four years would require an annual payment of $29.180 million, as calculated by the Company, before application of the 6% New Jersey Sales and Use Tax ("SUT"). With the SUT, the level payment was $30.931 million.[18] In contrast, the deferred balance, net-of-tax, is $59.467 million ($100.536 less the related tax reduction of $41.069 million at the composite rate of 40.85%). Recovering the net-of-tax balance on the same levelized basis, and for comparative purposes assuming the same 6.25% interest rate and four-year recovery period assumed by RECO, would reduce the level annual payment to $27.499 million before application of the SUT, and $29.149 million with the SUT.[19]

While RECO did not recalculate its proposed BGS deferred balances recovery on a net-of-tax basis, on cross-examination on February 19, 2003, witness Marino agreed with Staff that whether a gross or net of tax balance should be used depends only on the tax

[17] As shown on page 6 of Schedule FPM-1of RECO-7 and RECO-2. In a further update provided by letter dated July 3, 2003, and which supplied actual data through May 31, 2003, the interest accrual on the aggregate deferred balance (the combined SBC, ECA and BGS balances) was revised slightly to $8.925 million, including $9.372 million on the BGS balance alone, with "negative" interest on over recovered balances accounting for the difference. In recommending net-of-tax treatment prior to its acceptance by the Company, the RPA's witness James D. Cotton proposed an interest reduction of $5.540 million (R-4 7-20 to 22), and the Auditors proposed a reduction of $5.353 million for the three years ended July 31, 2002 (S-8, pages 25 and 28), which was subsequently slightly revised in S-11.

[18] The payment was revised slightly, to $30.139 million, in the July 3, 2003 update.

[19] The level payment ($16.266 million) needed to recover the net of tax balance at RECO's assumed interest rate, net of tax (3.70%), grossed up by dividing the payment by (1 - 0.4085).

benefit received during the period the deferred costs were incurred, and not on how they are permanently financed, be it through securitization or amortization with appropriate carrying costs. (1T 61-62).[20] He also acknowledged that all securitizations approved by the Board to date have been structured on a net-of-tax basis (I.D. at 61), and that RECO's Securitization Petition has been structured on a net-of-tax basis. (I.D. at 60-61). Accordingly, consistent with our prior rulings on the net-of-tax issue, the Board **HEREBY FINDS** that the interim recovery of the Company's deferred BGS balance should be determined on a net-of-tax basis.

2) "Net-of-Tax" Treatment of Post-Transition Deferred Balances

While RECO proposed that deferred accounting with interest continue to be used for its SBC and ECA cost recovery going forward, and that its related SBC and ECA charges be adjusted annually on August 1st in accordance with its proposed Plan approved by the Board, with modifications, in the Company's restructuring proceeding (RECO-7 at 19; RECO Reply Brief at 19-20), RECO did not address the rate at which interest on post-August 1, 2003 deferrals should be accrued, nor did the RPA.[21] Staff proposed using the Company's actual cost of short-term debt (debt maturing in less than one year), or if no short-term debt were outstanding, the rate on equivalent temporary cash investments. Staff additionally recommended that the interest rate, as well as the deferred balance to which it is applied, be determined net-of-tax, and for the same reason, i.e., because the interest provides a tax benefit during the deferral period in the same way the deferred costs do.

The Board is persuaded by Staff's reasoning on these issues, and **HEREBY ADOPTS** Staff's recommendations in this regard. The Board notes that during cross-examination at the February 19, 2003 hearing, Company witness Marino acknowledged the existence of a tax benefit as a result of accrued interest. (1T:63-2 to 18). Accordingly, consistent with our prior rulings on the net-of-tax issue, the Board **HEREBY APPROVES** net-of tax treatment of RECO's post-Transition Period interest accruals on its deferred balances, both with respect to the rate and the balances to which it is applied. Since RECO's SBC and ECA charges will be revised annually, the Board also **HEREBY FINDS** that interest on the SBC and ECA deferrals should be accrued at the Company's monthly actual cost of short-term debt, or in the event no short-term debt is outstanding, the rate on equivalent temporary cash investments, as proposed by Staff. Moreover, these findings shall also apply to interest accrued on RECO's BGS deferrals.

3) Interim Recovery of the BGS Deferred Balance

As noted above, the Board's March 25, 2003 Secretary's Letter stated that the Board would consider proposals for the interim recovery of the BGS deferred balance pending its decision on the broader issue as to the ultimate recovery mechanism to be accorded

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[20] Witness Marino conditioned his agreement on the allowance of an appropriate carrying charge. Note that "required" appearing in line 20 on page 62 of the transcript should have been "financed."

[21] The RPA did., however, strongly support the use of the net-of-tax methodology. (RIB at 53-54).

the Company's deferred BGS balance. The parties have set forth interim recovery proposals in this regard, which will be discussed herein.[22]

In his Direct Testimony filed on August 30, 2002 (RECO-7), Company witness Marino indicated that RECO anticipated filing a petition to securitize its deferred BGS balance over 15 years at an interest rate lower than its cost of capital. Based on a deferred BGS balance of $110.5 million projected at that time, including interest, he estimated that securitization would require an approximate $12 million, or 9% annual rate increase, as compared to an approximate $34.0 million, or 24.5% rate increase that would be required to recover the BGS balance over four years at an assumed seven-year debt rate of 6.25% (which rate would be revised on August 1st each year under RECO's proposal). (RECO-7 at 13; Schedule FPM-1 at 1). In the event the requested securitization were approved but not implemented by August 1, 2003, RECO proposed implementing the four-year deferral recovery rate on that date and keeping it in place until any authorized transition bonds were issued, at which time the lower securitization recovery rate would become effective. (RECO-7 at 13-14).

While believing that EDECA, as initially enacted, provided the Board with the requisite authority to allow securitization of the Company's deferred BGS balance, witness Marino acknowledged that there had been some debate over the issue, and alluded to then-pending legislation, Senate Bill 869, that would explicitly provide the Board with such authority. (RECO-7 at 14-15). That bill was ultimately passed and signed into law on September 6, 2002, thereby amending the EDECA to allow, in addition to generation and NUG buyout-related stranded costs, a third cost category, "Basic Generation Service Transition Costs," to be eligible for securitization, if approved by the Board.

Accordingly, on November 8, 2002, RECO filed a petition seeking the issuance by the Board of a Bondable Stranded Cost Rate Order that would authorize the Company to issue up to $68 million of transition bonds, or such higher amount as may be required to recover its Basic Generation Service Transition Costs.[23] The principal amount of the transition bonds for which RECO sought authority to issue was based on its deferred BGS balance of $110.5 million initially projected in this proceeding, net-of-tax ($65.4 million), plus estimated "up front" transaction costs of $2.5 million. Assuming 15-year recovery at a 6.57% interest rate, RECO calculated a first-year transition bond charge (including associated income and sales taxes) of $9.9 million, representing a 7.2% rate increase, compared to the $34.0 million, 24.5% increase that would be required if the initially-projected deferred BGS balance were recovered over four years.[24]

For illustrative purposes only, RPA witness James Rothschild used the same estimate of RECO's post-transitional BGS deferred balance in his Direct Testimony (R-14). He

[22] More precisely, the Company and the RPA responded to Staff's proposal in their Reply Briefs.

[23] See, Footnote 3, supra.

[24] As shown in Exhibits A through D and Exhibit F, Attachment F-1, attached to the Securitization Petition. In a subsequent updated filing, RECO's proposed four-year amortization was reduced to $30.9 million (22.3%), including SUT.

recommended that, to avoid rate shock, the deferred BGS balance be amortized over ten years at a fixed interest rate of 60 basis points above the seven-year treasury note rate, the rate approved by the Board for accruing carrying costs on the deferred balances of the State's other electric utilities during the Transition Period (and ultimately RECO's, starting on July 22, 2002, as discussed above). Moreover, he maintained that securitization over 15 years would be more expensive than amortization over that same period at his recommended interest rate.[25] However, he recognized that the purpose of this proceeding was to determine what portion of the deferred balance had been prudently incurred and eligible for securitization, and that the issue as to whether or not securitization is appropriate and in the best interest of ratepayers was to be determined by the Board in a separate proceeding, i.e., in Docket No. EF02110852 . (R-14 at 3-6).

In rebuttal testimony filed on January 31, 2003 (RECO-9), RECO witness John Perkins took issue with witness Rothschild's interest rate recommendation and his securitization analysis. Finding witness Rothschild's recommended use of the seven-year treasury rate plus 60 basis points regardless of the length of the recovery period to be unsupported and arbitrary, witness Perkins asserted that unless they can be legally separated from the rest of the Company's assets, utility assets should typically earn a return equal to the Company's overall cost of capital. (RECO-9 at 2). With respect to the deferred balance, however, he claimed that, even assuming the allowance of a full return, a recovery period as long as 10 to 15 years for costs that are normally recouped virtually simultaneously with the expenditure could, for that reason, still be viewed negatively by credit rating agencies and investors. (I.D. at 3).

In its Initial Brief, Staff noted that in light of the filing of the Company's Securitization Petition, which will be separately considered and decided by the Board, the BGS deferral recovery recommended in this proceeding should be interim only; that is, limited to the period from August 1, 2003 until the date of securitization closing, or other date on which amortization in lieu of, or in combination with securitization, as determined by the Board begins, assuming such date is later than August 1, 2003. Staff concurred with the RPA's proposed 10-year amortization period. With respect to carrying charges, Staff recommended that, in view of the short period in which the interim recovery was anticipated to be in effect, the rate on seven-year treasuries plus 60 basis points previously authorized by the Board be reduced to the rate on one-year treasuries plus 30 basis points, or to 1.6%, based on the yields reported in the Federal Reserve Statistical Release dated March 3, 2003. Additionally, as discussed above, Staff recommended that the balance be recovered net-of-tax.

Applying Staff's recommendations to Staff's recommended recoverable deferred BGS balance of $82.797 million (the balance based on RECO's December 2002 update reflecting actual data through November 2002, reduced by Staff's recommended disallowances) yielded a BGS deferral recovery of $8.717 million per year before

[25] Due to upfront transaction costs and a higher rate spread to treasuries (R-14 at 7). Thus, he found the deferred balance recovery rate per kwh to be approximately 4.7% to 6.7% higher for securitization relative to amortization for recovery periods ranging from four to fifteen years (I.D.. Table 1 on page 10).

application of the SUT and $9.240 million with the SUT.[26] Staff stressed that its proposed recovery was to be effective only in the interim period prior to the Board's anticipated consideration and final determination in Docket No. EF02110852, and until any authorized transition bonds were issued. (SIB at 28-31).

In its Reply Brief, RECO adhered to its proposed four-year recovery in the absence of securitization, and took issue with the ten-year amortization period proposed by the RPA and Staff. RECO also opposed the short-term interest rate recommended by Staff, maintaining that it was seriously understated, in that it did not match the recovery period. RECO asserted that, at a minimum, the rate should be RECO's "current seven-year debt rate plus the current RECO spread." (RECO Reply Brief at 18-19).

The RPA, in its Reply Brief, countered that both it and Staff agreed that the Company's overall rate of return should not be used as the carrying cost rate. Additionally, the RPA stressed that the ten-year amortization period it proposed was necessary to avoid rate shock. (RPA Reply Brief at 10-11).

The Board has carefully reviewed the position of the parties on this issue and agrees with the recommendations of Staff. The Board notes that its decision on this issue is a transitional one, until a final resolution of the Securitization Petition is rendered and implemented. The Board agrees with Staff and the RPA that RECO's overall rate of return should not be used as the transitional carrying cost rate. In the Board's view, it would not be appropriate to implement a near 25% rate hike now, only to likely implement a large rate reduction following our decision on RECO's Securitization Petition, which if approved as filed, could result in the issuance of transition bonds having a term of 15 years. Even if the Board were to decide that an amortization is more appropriate, the amortization period could well be closer to the ten-year period recommended by Staff and the RPA than the four-year period espoused by RECO.

With respect to carrying costs, RECO's contention that the rate must take into account the length of the recovery period would clearly be relevant and valid were the Board to be ruling on a permanent financing mechanism for the deferred balances. However, the Board's only concern at this time is the establishment of a transitional financing mechanism of very limited duration. As discussed by Staff, the intention of this transitional financing mechanism would be to compensate the Company in the short-term for its interest costs actually incurred in financing the deferred balance during a period of record low interest rates pending securitization or other permanent financing.

Accordingly, for purposes of interim recovery of RECO's deferred BGS balance pending our decision on its securitization petition, the Board **HEREBY FINDS** a ten-year amortization period to be appropriate, and that carrying costs on the unamortized balance during the period of interim recovery should be accrued at a rate equal to the rate on one-year constant maturity treasury notes plus 30 basis points, or 1.3%, based on the rate for the week ending June 27, 2003, as reported in the Federal Reserve

[26] Adjusted and corrected in Staff's Reply Brief to annual recovery of $8.560 million and $9.074 million, without and with SUT, respectively, based on a recoverable deferred BGS balance of $81.308 million. (SRB at 3-4 and Appendix SRB-1).

Statistical Release dated July 1, 2003. Moreover, after reflecting RECO's July 2003 update, based on actual data through May 2003, and the disallowances and related adjustments discussed below, the recovery shall be based on an estimated deferred BGS balance of $83.6 million as of July 31, 2003. The recovery of the balance shall be determined on a net-of-tax basis, as indicated above, yielding, on an annual basis, interim BGS deferral recovery of $8.718 million per year before application of the SUT, or $9.241 million with the tax applied.

Finally, the estimated recoverable BGS balance of $83.6 million shall be subject to a true-up to reflect: 1) additional actual data through July 31, 2003; 2) the results of the Board's Phase II audit of the Company's deferred balances; and 3) a re-calculation of the accrued interest to reflect all such disallowances and adjustments. At our public meeting on February 11, 2004, we accepted and released for comment the Phase II Audit Report performed by Larkin & Associates, PLLC and Synapse Energy Economics, Inc., which, in addition to the auditors' findings, reflected actual data through July 31, 2003 and the revised interest calculation ordered herein. Upon the Board's review of the comments and final acceptance of the Phase II report, its findings, subject to modifications reflecting the comments received, are to be incorporated into the Company's charges for BGS effective June 1, 2004. Stated another way, the difference between the deferred BGS balance assumed herein and the audited balance is to be remitted/recovered from ratepayers over one year via an adjustment to the Company's BGS charges effective June 1, 2004. In the event the final Phase II Report is not approved by the Board in time for its findings to be so reflected, the findings of the report as released on February 11, 2004 will be incorporated on an interim basis, subject to a further true-up to be incorporated in the Company's BGS charges when they are next changed.

2. Consumer Education Program ("CEP")

The ALJ determined that RECO is entitled to recover $446,000 as its share of the costs of the CEP. (I.D. at 25-26). The Board **HEREBY ADOPTS** the ALJ's decision with respect to this issue. As the I.D. notes, the amount of RECO's CEP costs was not in dispute. The RPA recommended disallowance of these costs on the grounds that RECO failed to show that the CEP costs were reasonably and prudently incurred. However, RECO has provided evidence demonstrating that its CEP expenditures were made pursuant to Board Orders. Moreover, as the ALJ correctly observed, at no time did the Board find specific flaws with RECO's conduct of its CEP and, in fact, the Board's consultant with respect to the CEP, the Center for Research and Public Policy, specifically concluded that the utilities had met or exceeded their program obligations. Accordingly, the Board **FINDS** that RECO is entitled to recovery of these costs.

3. The Other Components of the Company's Unbundled Rates

As discussed above, RECO's Societal Benefits Charge recovers the cost of demand side management and renewable energy and efficiency programs (now collectively known as "Clean Energy Programs"), the cost of educating consumers about retail choice (CEP costs), and Universal Service Fund costs, which during the 2002-2003 heating season provided $200 bill credits to low income customers to assist them in paying their winter utility bills. Staff found the Company's actual and projected levels of these costs, as described on pages 16 through 19 of RECO-7, and as updated in Schedule FPM-4 of RECO-2, to be reasonable. With the exception of CEP costs, discussed above, the RPA also found the Company's SBC costs to be reasonable.

RECO's Energy Cost Adjustment collects its share of the above-market component of the cost of O&R's non-utility generation contracts. As of July 31, 2003, the ECA was projected to be over-recovered by about $9.0 million, including interest. (RECO-2, Schedule FPM-3; FPM-1, page 3). RECO proposed to use the over-recovered balance to: 1) offset net unrecovered above-market NUG costs of $3.7 million anticipated to be incurred over the remaining lives of the contracts; 2) offset deferred restructuring proceeding costs of $1.9 million; 3) offset $1.7 million of excess refunds associated with the Temporary Credit implemented in the final year of the Transition Period to meet the Board-ordered rate reduction, as required by EDECA; and 4) to reduce the under-recovered SBC deferred balance by $1.7 million. (RECO-2, Schedule FPM-1, page 3).

Staff and the RPA did not dispute these costs. However, the RPA proposed deducting the $3.7 million of the over-recovered ECA balance that RECO proposes to apply to prospective ECA under-recoveries from the deferred BGS balance instead, and to credit the excess refund associated with the Temporary Credit to the BGS balance. The RPA argued that the remaining ECA over-recovery should not be used to offset the under-recovered SBC balance. (RIB at 40-42). As discussed above, Staff supported RECO's position on these issues (SIB at 32-33). The ALJ agreed with the RPA. (I.D. at 27).

Essentially, the issue here is what to do with the ECA over-collection of approximately $9.0 million, in that no party has challenged the relevant costs claimed by the Company. The difference in the end result achieved by the treatments proposed by the RPA and RECO is relatively small. The accrual of interest on the difference will compensate the ratepayer for any delayed "refund" that might result under RECO's proposal, which appears to have the added advantage of moderating the increase in the SBC rate and, in turn, minimizing relatively small rate changes going forward. Accordingly, the Board **FINDS** RECO's proposal to be acceptable, and slightly superior to the RPA's, and **HEREBY MODIFIES** the ALJ's finding on this issue accordingly.

4. Other Issues

a) Internal Labor Costs Included in BGS Auction/ PJM Transfer Costs

RPA witness Cotton recommended that $0.325 million of internal labor and overhead costs be eliminated from the $1.143 million of BGS auction/PJM transfer costs claimed by the Company (RECO-2, Schedule FPM-2, at 1) on the basis that such costs are not incremental, but are already provided for in RECO's base rates. (R-4 at 21-22; R-4, Appendix C). Staff agreed with the RPA on this issue. (SIB at 33) The ALJ ruled in favor of the Company. (I.D. at 19-20). The Board disagrees with the ALJ.

Based on its review of the record, the Board finds nothing in the record to support the

Company's contention that these costs were incremental (over and above costs already included in base rates). The record reflects that these costs were associated with the installation of the metering and telecommunications equipment necessary to complete the PJM Transfer and participate in the Year 4 BGS Auction. Although it is true that this specific undertaking was not contemplated when RECO's 1992 base rate case was decided, it is well-established that a representative test year level of internal labor expenditures, which would include expenses of this nature, are included in base rates, and, if these rates are insufficient, the Company has the option of filing a base rate case petition. To include such expenditures in the deferred balance would provide the potential for an improper double recovery (recovery in the deferred balance and recovery in base rates). The Company has presented nothing in the record to show that these internal labor costs have not been recovered in current base rates or that these costs have not been included in the test year level of labor costs in its pending base rate case conducted concurrently with the deferred balances proceeding.

In summary, the Board finds that the appropriate recovery mechanism for the asserted increased internal labor costs is through base rates and not through the deferred balance. Accordingly, after reviewing the record on this issue the Board is unpersuaded that this additional $0.325 million expense claimed by the Company represents an appropriate incremental expense for inclusion in RECO's deferred balance. Therefore, the Board **HEREBY REJECTS** this finding of the Initial Decision and **HEREBY ORDERS** a disallowance of $0.325 million from RECO's deferred BGS balance.

b) PJM "Loop Flow" Adjustment

As part of the Phase I audit of RECO's deferred balances, the Auditors identified an issue involving the allocation of a portion of the energy purchased from PJM for RECO's Eastern Division to O&R's New York customers. As shown in the table on page 13 of S-8, from 6.2% to 13.8% of the energy purchased from PJM in the months of March 2002 through July 2002 wound up in New York, apparently as a result of unintended "loop flows." The Auditors raised this as an issue, since all the costs of accomplishing the PJM transfer was allocated to New Jersey, while it appears that some of the benefits of the transfer are flowing to New York customers. While O&R's New York customers apparently paid for this energy, given, on average, the lower cost of energy purchased from PJM as compared to the NYISO, both the Auditors and Staff expressed a concern about whether the Eastern Division, i.e., RECO's New Jersey ratepayers, may have incurred higher BGS costs from having to replace the errant PJM energy with NYISO purchases.

While the Auditors did not quantify or recommend an adjustment as part of their report, Staff quantified the resultant increased cost attributable to the higher cost of NYISO purchases to be $0.804 million, and recommended disallowing this amount from the Company's deferred BGS balance. (SIB at 34; SRB at 3, Appendix SRB-1). The Company took issue with Staff's quantification, claiming that insufficient evidence in the record existed to support Staff's disallowance quantification. The ALJ did not address this issue. The Board **HEREBY FINDS** that the unintended loop flows appear to have caused a modest amount of energy purchased from PJM to end up in O&R's service territory and that there is some merit to Staff's recommendation that New Jersey ratepayers be compensated therefor. However, because the amounts were relatively small and because the record on this issue was not sufficiently developed so as to enable an appropriate quantification, the Board will not make an adjustment to RECO's BGS deferred balances.

c) Mitigation of Above-Market NUG Costs

In its Initial Brief RECO asserted that in view of its limited exposure to over-priced NUG contracts (approximately 10 Mw), the Auditors did not find that its failure to renegotiate or buy out these contracts was imprudent. (CIB at 27). However, this observation omitted the context of the Auditors' finding:

> We find the Company's explanation reasonably persuasive. Nevertheless, we would have liked to have seen some effort by the Company to talk with the NUGs about restructuring the contracts. It may have been true that RECO's 10 Mw of NUG contracts represented only 2.5% of its supply needs at the start of the transition period and, therefore, there were other, more pressing issues that required management's attention. However, over time, the above-market NUG contracts increased the amount of deferred balances by approximately $2 million to $2.5 million per year. (Exhibit FPM-3). This was not an inconsequential amount. This amount also would have been substantially higher if, as the Company says it anticipated in 1999, future energy market prices would be lower due to increased market liquidity and competition.
>
> [S-8 at 62].

The Company represented to the Auditors that none of the owners of its NUG projects were willing to be bought out. Moreover the Company was skeptical of any potential benefit that might result from such renegotiations or buyouts.

The Board disagrees. N.J.S.A. 48:3-50.c.(4) specifically requires that any proposed recovery of above-market power generation and supply costs as well as other reasonably incurred costs associated with restructuring be "subject to the public utility having taken and continuing to take all reasonably available steps to mitigate the magnitude of its above-market electric power generation and supply costs." Particularly in view of the success the State's other electric utilities have had in mitigating the above-market costs of their NUG contracts, the Board believes that this is an area clearly worthy of more aggressive pursuit by the Company, in order to achieve maximum benefits to ratepayers, consistent with applicable law. Accordingly, the Board **HEREBY AFFIRMS** the spirit and intent of the EDECA language quoted above, and strongly urges RECO to initiate discussions with the owners of the NUG projects for which it is being allocated above-market power by its parent company, in order to explore the possibility of similarly mitigating the above-market NUG costs of from $2 to $2.5 million per year identified by the Auditors. The Board **HEREBY DIRECTS** the Company to file a report with the Board indicating the initial results of such efforts by no later than 90 days from the date of this Order, and to continue to file quarterly status reports thereafter.

These status reports shall be in addition to, and consolidated with, the monthly reports the Company was directed to file by the Summary Order in these Dockets issued on July 31, 2003, which we hereby slightly modify as follows. As issued, the Summary Order directed the Company to file monthly reports with the Board, showing for the Company's share of the capacity and energy purchased from each of the NUG projects with which the parent company has a PPA, "the energy and capacity purchased (Mwh and Mw), the amount paid for the energy and capacity, the disposition of the energy and capacity (i.e., whether it was resold in the wholesale market or otherwise), as well as the value of the energy and capacity if priced at the average monthly PJM and NYISO LMPs and capacity deficiency rates, and the rate payable for BGS supply obtained pursuant to the statewide auction." We **HEREBY MODIFY** this directive to 1) add the phrase "for the Zone in which RECO operates" after "LMPs;" and 2) to replace "capacity deficiency rates" with "the average rates at which capacity sales were transacted during the month;" and 3) to replace "rate payable for BGS supply obtained pursuant to the statewide auction" with the "energy and capacity component of the rate payable for BGS supply obtained pursuant to the statewide auction, or if not known precisely, a reasonable estimate thereof." The Board notes that the first such report was due 30 days from the date of the Summary Order.

d) Feasibility of Transferring Central and Western Divisions to PJM

During the cross-examination of RECO witness Holtman, Staff inquired as to whether the Company had analyzed the economics or feasibility of having RECO's Central and Western Divisions, which serve approximately 10 percent of its load, also transferred to the PJM control area. (7T at 196-198). Although admitting that the Company had performed no such studies, witness Holtman asserted that there was a general understanding that such a transfer would be prohibitively expensive. In view of the potential benefits of such a transfer, as evidenced by the significance of this issue in this proceeding, the Board agrees with Staff that this possibility at least merits a formal analysis. Accordingly the Board **HEREBY DIRECTS** the Company to conduct such a study, and to report its results by no later than 90 days from the date of this Order.

5. Summary of Board Findings on Deferred Balances

a) Deferred BGS Balance

1. Based on a projected deferred BGS balance of $102.003 million as of July 31, 2003, including interest of $9.372 million,[27] less: 1) a disallowance of $8.185 million to reflect the Company's (i.e., the parent company's) imprudence in failing to extend the energy component of the TPSA with Mirant through the summer of the year 2000; 2) a disallowance of $2.213 million representing increased BGS costs attributed to an avoidable 6-month delay in transferring the Eastern Division to PJM; 3) a disallowance

[27] Schedule RM-1 at 2, July 3, 2003 update reflecting actual data through May 2003.

of one-half of the hedging costs found excessive by the Board ($5.817 million);[28] 3) a disallowance of $0.325 million of internal labor costs not shown to be incremental to the labor costs included in the Company's present rates; and 4) an estimate of the interest associated with these disallowances of $1.900 million,[29] the Company is **HEREBY AUTHORIZED** to recover a deferred BGS balance of $83.6 million.

2. This balance shall be trued-up to reflect the results of the Phase II Audit, as described above.

3. For purposes of interim recovery pending the Board's decision on the Company's securitization petition, the deferred BGS balance shall be recovered net of tax, as illustrated in Exhibit 1 attached to this Order, over 10 years, with interest at the rate on one-year constant maturity treasury notes plus 30 basis points, determined herein to be 1.3%.[30] When applied to the deferred BGS balance of $83.6 million approved for recovery herein, the net of tax methodology yields interim deferral recovery of $8.718 million per year[31] before application of the 6% New Jersey Sales and Use Tax, and $9.241 million per year with the tax applied. The Board **HEREBY APPROVES** this recovery on an interim basis pending the Board's decision on the Company's securitization petition.

b) SBC, ECA and MTC Deferred Balances (Deferred Restructuring Proceeding Costs and Temporary Credit)

1. As discussed above, the Board **HEREBY APPROVES** the Company's proposed rate treatment of the deferred balances associated with these components of its unbundled rates, *i.e.*, that the over collected deferred ECA balance be used to offset: 1) the excess refund of the Temporary Credit; 2) deferred Restructuring Proceeding costs; 3) anticipated future under-recoveries of above-market payments made under PPAs with non-utility generators; and 4) a portion of the under-recovered SBC deferred balance, all as proposed by the Company. Accordingly, the ECA charge shall continue unchanged, and the MTC/Temporary Credit shall be terminated effective August 1, 2003. For purposes of determining the projected July 31, 2003 deferred balances of the ECA and SBC, as well as the ongoing component of the SBC (the costs to be recovered during the 12 months ended July 31, 2004), and subject to ongoing annual true-ups and the results of the Phase II Audit, the Company is **HEREBY AUTHORIZED** to employ the July 3, 2003 update (Schedules RM-1 through RM-9). The Company is additionally **HEREBY AUTHORIZED** to include in the USF component of the SBC the additional

[28] Schedule FPM-2 at 1, December 31, 2003 update reflecting actual data through November 2002 (RECO-2).

[29] $9.372 million less $7.417 million from Appendix SRB-2 at 4 of Staff's Reply Brief, less an allowance for "loop flow" interest of $0.055 million.

[30] Based upon the rate for the week ending June 27, 2003, as reported in the Federal Reserve Statistical Release dated July 1, 2003.

[31] $83.6 million divided by 9.58977, where 9.58977 is an annuity factor with n = 10 years and i = 0.76895% (1.3%, net of tax).

USF costs authorized by the Board's Order in Docket No. EX00020091 dated July 16, 2003.[32] Finally, when the ECA is next revised pursuant to a further Order of the Board, it shall be re-named the NGC ("non-utility generation charge"), a change we will also require of the other electric utilities to standardize the unbundled rate component that recovers above-market NUG purchased power costs.

2. The Board **HEREBY** **APPROVES** continued use of deferred accounting, with interest, for under and over-recoveries of costs recoverable by the SBC and ECA, as well as for under and over-recoveries of costs incurred in supplying BGS, which shall be recorded as regulatory assets and liabilities on the balance sheet. Effective August 1, 2003, interest on the deferred costs shall be accrued at the Company's actual rate on short-term debt/temporary cash investments, net of tax, as discussed above and illustrated in Exhibit 2 attached hereto.

c) NUG Reporting Requirements

The Company is **HEREBY** **DIRECTED** to supply on a monthly basis the NUG cost and other data described more fully above. The first such report was due 30 days from the date of the Summary Order (*i.e.*, by September 1, 2003). That and all other reports filed prior to the date of this Order shall be re-filed to reflect the changes in the data required to be reported, as specified above. The Company shall also file quarterly reports advising the Board as to the status of its (the parent company's) efforts to negotiate buydowns or buyouts of its NUG PPAs.

The first such report will be due 90 days from the date of this Order.

d) Feasibility Study, Transfer of Western/Central Divisions to PJM

As described above, this study shall be filed within 90 days of the date of this Order.

B. Base Rate Case

The Board **HEREBY** **ADOPTS** and incorporates by reference as if completely set forth herein, the ALJ's Initial Decision with respect to the base rate case, as updated by RECO's "12+0" actual numbers, with the following exceptions and/or modifications:

1. RATE OF RETURN AND CAPITAL STRUCTURE

The Board **HEREBY** **REJECTS** the ALJ's findings on these issues. The ALJ concurred with RECO's position that a 12% return on equity with an overall rate of return of 9.33% is appropriate and, in so doing, rejected the RPA's 9.25% ROE and 7.92% overall rate of return recommendations, as well as Staff's recommendations of 9.5% ROE and 7.90% overall rate of return. Further the ALJ accepted RECO's proposed capital structure of 50.69% Common Equity and 49.31% Long-Term Debt.

[32] *I/M/O the Establishment of a Universal Service Fund Pursuant to Section 12 of the Electric Discount and Energy Competition Act of 1999.*

Based on our review of the record, and for the reasons described herein, the Board **<u>HEREBY</u> <u>FINDS</u>** the ALJ's recommendations to be excessive. The Board **<u>FURTHER FINDS</u>**, on balance, that Staff's analysis, as modified herein, is a more reasonable and appropriate resolution of the rate of return and capital structure issues, particularly in light of current market conditions as well as RECO's new regulatory position in the restructured electric market in New Jersey.

a) Rate of Return

It is well-established that a public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public, equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings, which are attended by corresponding risks and uncertainties. <u>Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia</u>, 262 <u>U.S.</u> 679, 692 (1923). However, the Board is empowered to determine what, in a particular situation, is a just and reasonable return for a public utility and it has broad discretion in the exercise of that authority. <u>Atlantic City Sewerage Co. v. Board of Public Utility Com'rs</u>, 128 <u>N.J.L.</u> 359 (1942), <u>aff'd</u> 129 <u>N.J.L.</u> 401. Board-approved public utility rates will be considered valid so long as they enable the utility to operate successfully, maintain its financial integrity, attract capital and compensate its investors for the risk assumed. <u>FPC v. Hope Natural Gas Co.</u>, 320 <u>U.S.</u> 591, 605 (1944). Stated another way, if the total effect of the rate order is not unreasonable, judicial inquiry is at an end. (I.D. at 602). Thus, a cost of equity figure is appropriate so long as it is "within the range of reasonableness, the zone between the lowest rate not confiscatory and the highest rate fair to the public." <u>In Re N.J. Power & Light Co.</u>, 9 <u>N.J.</u> 498, 535 (1952).

In determining the cost of equity capital for a regulated utility, rate of return experts typically use a variety of financial models to simulate the returns assertedly required by investors. These include Discounted Cash Flow models, Risk Premium models, Capital Asset Pricing Models, Comparable Earnings models and variations thereof. However, it is widely acknowledged that these economic models constitute mere estimates, which, although probative, are frequently imprecise and ambiguous. The ambiguities and imprecision in the forecasts provided by these models are more pronounced as a result of the new economic environment brought about by EDECA. Nevertheless, it is incumbent upon this Board to define a fair rate of return for RECO.

Here, although RECO witness Mr. Rosenberg and RPA witness Mr. Rothchild testified concerning the derivation of various point estimates which yielded resultant ranges for ROE and ROR, their computations were based on the use of market prices for the common stock of companies that are not sufficiently comparable to the "new" RECO in the restructured electric market in New Jersey. The restructuring of the electric industry in New Jersey has transformed RECO into a "wires" company, subject to advantageous regulatory policies embedded in EDECA. Typically, vertically integrated electric companies are riskier than pure "wires" companies. Neither Mr. Rosenberg nor Mr. Rothchild fully factored this presumption into their models when selecting "comparable" companies. Moreover, the presence of non-regulated riskier investments in the comparable companies can cause an upward bias in the estimate of the expected returns for the less risky RECO. In Staff's Initial Brief at 37 to 46, Staff provides a comprehensive analysis of the various negative elements of the models provided by the witnesses.

In addition to the weaknesses in the financial models provided in the record, the Board has factored into its decision several regulatory features that do not fit into any of the formulaic financial models utilized by the witnesses. In particular, subsequent to August 1, 2003, RECO is in a position to pass through all power costs contracted for via the BGS auction. There is every indication that this method of power acquisition for its customers will continue for quite some time and substantially eliminate risks previously associated with power procurement. Moreover, whether by securitization or by traditional amortization, RECO is also assured of recovering in rates all prudently incurred deferred balances. Finally, rate caps were removed effective August 1, 2003 and thus going forward, RECO will be able to access the Board's rate adjustment process should distribution costs increase.

In light of the positive regulatory changes resulting from EDECA, as well as the current low interest rates and low inflation rates, it is clear that RECO's return on equity should be reduced from the current 12% set over ten years ago, in 1992. Although the ALJ justifies maintaining RECO's 12% ROE on the basis that "the company still faces regulatory risks," he fails to indicate exactly what those risks are and whether or not the risks have been diminished as a result of RECO's becoming a "wires-only" utility. (I.D. at 36). In view of the analysis provided by Board Staff and the RPA, the Board is persuaded that RECO's overall level of risk is much lower now than when the 12% ROE was set back in 1992. <u>See</u> Staff's Initial Brief at 36 to 48. <u>See</u> <u>also</u> RPA's Initial Brief at 10. Therefore, it is incumbent upon this Board to determine what the appropriate return on equity should be going forward.

It is only logical to begin this inquiry by discussing the 10% ROE this Board has allowed in recent years. As Mr. Rothchild correctly notes in his testimony, allowed ROE throughout the Northeastern portion of the United States has been steadily decreasing over the last few years to the current 10% level. Transcript of hearing dated 2/21/03 at 146-148. <u>See</u> <u>also</u> RECO - 49. Moreover, the RPA correctly indicates in its Initial Brief that 10% is the ROE this Board has deemed appropriate in several recent decisions. <u>See</u> <u>e.g</u>, <u>In the Matter of the Board's Review of Unbundled Network Elements Rates, Terms and Conditions of Bell-Atlantic-New Jersey, Inc.</u>, BPU Docket No. TO00060356 (Order dated March 6, 2002). <u>See</u> <u>also</u>, <u>I/M/O The Petition of Public Service Electric & Gas Company for Approval of an Increase in Gas Rates for Changes in the Tariff for Gas Service</u>, BPU Docket No. GR01050328 (Order dated January 9, 2002). Staff also notes this Board's acceptance of 10% ROE, citing <u>I/M/O Petition of NUI Utilities d/b/a Elizabethtown Gas Company for Approval of an Increase in Gas Rates for Changes in the Tariff for Gas Service</u>, BPU Docket No. GR020405245 (Order dated November 20, 2002). Staff's Initial Brief at 46.

It should be noted that the Staff, in making its revenue requirement recommendation, utilized a 9.5% ROE. However, Staff also noted that "for purposes of advising the

Board in this matter, a range of 9.5% to 10% is reasonable and consistent with recent Board decisions." Staff's Initial Brief at 46. In recognition of Staff's recommended more leveraged capital structure of 54% long-term debt and 46% common equity, the Board believes that a 9.75% return on equity is an appropriate adjustment to Staff's return on equity recommendation of 9.5%.

Accordingly, the Board **HEREBY APPROVES** a return on common equity that RECO shall be permitted to earn 9.75%. We additionally **HEREBY FIND** that the Company's cost of long-term debt is 6.54%[33], and after reflecting Staff's recommended capital structure of 54% long-term debt and 46% common equity, that the overall rate of return the Company shall be permitted to earn is 8.02%.

b) Capital Structure

In making its rate of return recommendation, Staff cited the reduction in the Company's cost of capital attributable to the truly historic reductions in interest and inflation rates that have occurred since the Company's base rates were last set some 10 years ago, as well as the significantly lower business and financial risk the Company now enjoys as a pure distribution company. The absence of generation risk at the parent company level, and, with the advent of the statewide auction, very little risk associated with obtaining BGS supply have combined to eliminate operational risk that in the past has typically been a major source of investor concern. Moreover, the elimination of the EDECA rate caps, the direct pass-through of BGS costs to customers, and the opportunity to seek securitization of the Company's deferred BGS balance have significantly reduced financial risk as well.

As argued by Staff, this new and substantially reduced risk profile justifies a lower equity component of the Company's capital structure (46%, or equivalently, a higher debt ratio of 54%) in contrast to the capital structure proposed by the Company and accepted by the Ratepayer Advocate (50.56% common equity and 49.44% debt).

In proposing its recommended capital structure Staff recognized that it should fall within the range found acceptable for an A-rated company by the rating agencies, notably Standard & Poor's ("S&P's"), which periodically publishes quantitative benchmarks for such important measures of creditworthiness as the debt ratio (debt as a percentage of total capital) and the interest coverage ratio (the ratio of pre-tax net income to annual interest payments). As stated in S&P's description of its rating methodology attached as Appendix SRB-3 to Staff's Reply Brief,[34] S&P uses a numbering system for evaluating the business and financial risk of utilities, with 1 representing the least risk, and 10 the highest. S&P goes on to note that "Companies with a strong business

[33] O&R's weighted average cost of long term debt of 6.78% as of April 30, 2003 (Exhibit P-4, Schedules 1 and 2 included in the "12+0" update), adjusted to reflect replacement debt for the $35 million of O&R's 6.56% Series D debentures redeemed on April 1, 2003. An interest rate of 4.5% was assumed for the replacement debt (the rate assumed by the Company, as indicated on page 6 of the supplemental testimony of RECO witness Kane included with the "12+0" update).

[34] In its Reply Brief (at 8), Staff requested that he ALJ take judicial notice of Appendix SRB-3.

profile – typically, transmission/distribution utilities – are scored 1 through 4; those facing greater competitive threats – such as power generators – would be assigned an overall business profile score of 7 to 10." (I.D. at 2).

The benchmarks employed by S&P accordingly reflect this risk assessment, with higher debt ratios and lower interest coverage ratios permitted for low risk utilities such as RECO as compared to higher risk utilities. For utilities having the lowest business risk ("Business Profile 1"), the debt ratio can range from 55% to 60.5%, and the interest coverage ratio can range from 1.8 times to 2.4 times. (I.D. at 15). Staff's recommended debt ratio accordingly is conservatively lower than the low end of this range, and the coverage ratio inherent in Staff's rate of return recommendation, at 2 times,[35] also falls within the range S&P finds acceptable for a minimum risk utility.

With no change in the other components of return, and as applied to the rate base recommended by the Company and the Advocate, Staff's proposed capital structure would yield reductions in the Company's and Advocate's revenue requirement positions of $0.819 million and $0.436 million, respectively. (Staff Reply Brief at 8-9).

In its Cross-Motion to Strike Portions of Staff's "Reply" Brief and Appendix filed with ALJ Gural on April 10, 2003 ("Cross-Motion"),[36] the Company contested Staff's capital structure recommendation, citing several due process concerns[37] as well as the arguments the Company set forth in its Reply Brief (as quoted in the Cross-Motion at 15) defending the use of O&R's consolidated capital structure as appropriate for RECO. The Company also asserted that the actual business profile assigned to RECO by S&P is 4, not 1, as employed by Staff in performing its pro forma coverage analysis. A business profile of 4 in turn would assertedly require a debt ratio in the range of 43.0% to 49.5% in order to maintain the "A" bond rating assumed by Staff. Moreover, even if RECO's business profile were to be upgraded to 3 at the conclusion of the base rate case, a debt ratio between 47.5% and 53.0% would still be required to maintain an "A" bond rating. (I.D. at 14-17).

By letter dated April 16, 2003, Staff filed its response to the Cross-Motion, maintaining, in pertinent part, that the Company's due process and substantive concerns were allayed by the admission into the record of the Company's brief in support of the Cross-

[35] The ratio of Staff's recommended ROE of 9.5% weighted at 46% of total capital and grossed up for income taxes (7.39%) to the Company's proposed embedded debt cost of 6.79% weighted at 54% of total capital (3.67%). After reflecting the 9.75% ROE allowed the Company by the Board and a weighted debt cost of 3.53%, this pro forma interest coverage ratio is increased to 2.1 times.

[36] Also filed with the Cross-Motion was the Company's opposition to Staff's motion to supplement the record by introducing as exhibits discovery responses on the consolidated tax issue (RECO's responses to S-RREV-147 through 151).

[37] The capital structure and other material associated with additional recommendations made in Staff's Reply Brief were asserted to "(1)…not properly reply to any materials in RECO's direct brief; (2) rely on extra-record hearsay materials not in evidence or subject to proper judicial notice; (3) deprive RECO of due process by foreclosing any cross-examination or rebuttal testimony; and (4) prejudice RECO by setting forth erroneous and misleading information." (Cross-Motion at 5).

Motion as well as the extensive rebuttal evidence (certifications) submitted by two expert witnesses. On April 17, 2003, ALJ Gural denied the Company's Cross-Motion.

In considering the substantive concern the Company raises relative to Staff's use of S&P's benchmarks applicable to a utility with a business risk profile of 1 as compared to 4, we believe that the issue here, like that on rate of return, is one of assuming the continuation of a profile based on risk factors reflective of RECO's past history in contrast to a forward-looking profile more reflective of the business and financial risk mitigating factors noted above. Accordingly, we **HEREBY APPROVE** the 54% debt ratio recommended by Staff as being more nearly reflective of these factors. Moreover, we consider the bond interest coverage ratio to be just as important, if not a more important financial parameter than the debt ratio, and as a practical matter, if achieved, the equity return authorized herein will result in a bond interest coverage ratio for RECO far in excess of the pro forma ratio calculated by Staff.[38] Finally, as noted above, in recognition of the increase in the debt ratio proposed by Staff relative to that proposed by the Company, we believe an increase in the allowed ROE, to 9.75% from the 9.50% recommended by Staff, is appropriate.

2. Rate Base

The Board **HEREBY ADOPTS** and incorporates by reference as if completely set forth herein, the ALJ's Initial Decision with respect to rate base issues subject to the following modifications:

a. Utility Plant In Service

As previously discussed, the ALJ adopted Staff's recommendations with respect to inclusion of the Oakland project in rate base and exclusion of the Upper Saddle River and the Darlington projects because those projects do not satisfy the Board's requirements for inclusion of post-test year additions established in the Elizabethtown case. (I.D. at 38). It is clear from the record that the post test year plant additions RECO anticipates completing in Upper Saddle River and Darlington are not sufficiently "known and measurable" at this time and that the construction project costs and timetables continue to be subject to numerous contingencies.

In its Exceptions to the Initial Decision, RECO argues that phases of the disallowed Upper Saddle River project (approximately $2.895 million) and the Darlington project (approximately $54,000) will be placed into service by the end of the test year, and thus should be included in base rates.

The Board has long required that projections for the cost of post-test year plant additions must be "carefully quantified through proofs which manifest convincingly reliable data." See, R-16, Board's Order in Elizabethtown, supra, at 2. While, as noted above, the Board agrees with and has affirmed the ALJ's decision to disallow rate base

[38] Based on approximately $20 million of RECO's long-term debt outstanding as of April 30, 2003 (Series J, 7.125% due February 1, 2007) and an allowed rate of return on common equity of 9.75%, RECO's bond interest coverage ratio would be approximately 6 times.

treatment of these items because they are not sufficiently "known and measurable" at this time, the Board is extremely sensitive to and concerned about issues relating to system reliability and, thus, **HEREBY AUTHORIZES** RECO to file a Phase II proceeding on or before September 1, 2004 to address the Upper Saddle River and the Darlington projects and the associated flow-through impacts that the record reflects and the ALJ properly found were not completed in the test year. The Board **HEREBY ORDERS** that RECO shall be permitted to include in this Phase II filing a request for recovery of the costs of completed reliability enhancements, which enhancements it had sought in this case, but which the record reflects and the ALJ appropriately concluded, had not actually been performed. The Board **FURTHER ORDERS** that the Phase II proceeding include consideration of whether the Upper Saddle River and Darlington projects provide plant additions necessary for transmission (in which case, they could possibly be subject to FERC regulation) or distribution (in which case, they could be subject to Board scrutiny). RECO shall have the burden of proof with respect to the classification of these facilities, including the appropriateness of including any transmission related investment or expense in distribution rates versus the FERC transmission rate.

b. Consolidated Tax Adjustment

As discussed supra, Staff proposed a consolidated tax savings adjustment reducing RECO's rate base by $1.329 million. (SRB at 13). The supplemented record reflects that, since 1999, RECO has been included in the consolidated federal income tax filings of CEI, along with CEI's other subsidiaries. (S-22). Moreover, even before CEI acquired RECO's parent company, O&R, RECO was included in O&R's consolidated tax returns. (S-19). As a result of filing on a consolidated basis, CEI pays less federal income taxes than it would if each of its subsidiaries filed separately, thus receiving significant tax savings.

Staff asserted that, if tax savings have been achieved by CEI by offsetting the tax losses of the Company's affiliates with positive taxable income from RECO, these savings should be shared with ratepayers. The tax savings are appropriately shared with RECO's customers because, were it not for the positive taxable income collected from ratepayers by RECO and the other regulated utilities within the group, CEI's tax savings would be significantly reduced. (SIB at 64).

It is well-settled law and Board policy that consolidated tax savings are to be shared with customers. I/M/O the Petition of Atlantic City Electric Company for Approval of Amendments to its Tariff to Provide for an Increase in Rates and Charges for Electric Service, Phase II, Docket No. ER90091090J (Order dated October 20, 1992) ("1992 Atlantic Electric Order"); I/M/O the Petition of Jersey Central Power and Light Company For Approval of Increased Base Tariff Rates and Charges for Electric Service and Other Tariff Revisions, Docket No. ER91121820J (Order dated June 15, 1993) ("1993 JCP&L Order"). The New Jersey courts have confirmed that the BPU has "the power and the function to take into consideration the tax savings flowing from the filing of a consolidated return and determining what proportion of the consolidated tax is reasonably attributable to [the utility]." Lambertville Water Company v. New Jersey Bd.

of Public Utility Com'rs, 153 N.J. Super. 24, 28 (App. Div. 1977), reversed on other grounds, 79 N.J. 449 (1979), (citing FPC v. United Gas Pipe Line Co., 386 U.S. 237, 87 S.Ct. 1003, 18 L.Ed.2d 18 (1967)).

In the Board's 1993 JCP&L Order, supra, the Board clearly explained that:

> The Board believes that it is appropriate to reflect a consolidated tax savings adjustment where, as here, there has been a tax savings as a result of the filing of a consolidated tax return. Income from utility operations provides the ability to produce tax savings for the entire GPU system because utility income is offset by the annual losses of the other subsidiaries. Therefore, the ratepayers who produce the income that provides the tax benefits should share in those benefits. The Appellate Division has repeatedly affirmed the Board's policy of requiring utility rates to reflect consolidated tax savings and the IRS has acknowledged that consolidated tax adjustments can be made and there are no regulations which prohibit such an adjustment. The issue, in this case, is not whether such an adjustment should be made, but rather, what methodology should be used to make such an adjustment. In this area, the courts have held that the Board has power and discretion to choose any approach which rationally determines a subsidiary utility's effective tax rate. Toms River Water Company v. New Jersey Public Utilities Commissioners, 158 NJ Super 57 (1978).
>
> Based on our review of the record in this case, the Board **REJECTS** the ALJ's recommendation to accept the income tax expense adjustment proposed by Petitioner and, instead **ADOPTS** the position of Staff that the rate base adjustment is a more appropriate methodology for the reflection of consolidated tax savings. The rate base approach properly compensates ratepayers for the time value of money that is essentially lent cost-free to the holding companies in the form of tax advantages used currently and is consistent with our recent Atlantic Electric decision (Docket No. ER9009190J). Moreover, in order to maintain consistency with the methodology applied in the Atlantic decision, we modify the Staff calculation and find that a rate base adjustment which reflects consolidated tax savings from 1990 forward, including one-half of the 1990 savings, is appropriate in this case.
>
> [1993 JCP&L Order at pages 7-8].

In this proceeding, RECO argued that: (1) it has had negative taxable income due to its deferred BGS balances; and (2) it has not contributed any income to offset losses from unregulated affiliates on a consolidated basis. (Cross-Motion, at 12). Although the ALJ was persuaded by these arguments, for the reasons discussed herein, the Board **HEREBY REJECTS** the ALJ's determination on this issue.

The Board **FINDS** that RECO's arguments were incorrectly based upon data from only the two most recent years. The 1991-2001 time period utilized by Staff is consistent with both the 1992 Atlantic Electric Order, and the 1993 JCP&L Order, supra, and appropriately compensates ratepayers for the value of money that has essentially been lent cost-free to the parent holding companies in the form of currently used tax advantages. In the 1993 JCP&L case, the Board determined that it was appropriate to utilize data from 1990 forward, including one-half the1990 savings. In the 1992 Atlantic Electric case, the Board explained that there may have been a period of time in the mind.-to-late 1980's where investors might have reasonably expected that the Board would not make consolidated tax adjustments because of certain IRS private letter rulings and they may have devised investment strategies based on that expectation. However, the Board further found that, "it is clear that at some point during the 1988-1991 timeframe, investors should reasonably have expected that prospective consolidated tax adjustments would or at least could be made." Therefore, the Board utilized data from 1991 forward, including one-half of the 1990 savings. In this case, Staff used a similar starting point, but began with 1991, in order to start with a full year period.

The Board agrees with Staff that RECO's argument that it would be improper to consider data from the period prior to the date of the merger between O&R and Con-Ed (i.e. July 1999) is not valid. RECO's positive net income during the years 1991-1999 clearly produced tax savings for its parent company in those years, and RECO's customers should not be denied their share of these savings simply because of a subsequent merger of its parent with Con-Ed.

The Board continues to believe that if a utility is part of a conglomerate which profits by consequential tax benefits from the utility's contributions, the utility customers are entitled to have a computation of their fair share of those benefits reflected in their utility rates. This ensures that the Company receives the use of the actual tax dollars saved, while ratepayers are not put in the position of providing the utility with a return on these dollars. Accordingly, the Board **HEREBY ADOPTS** the position of Staff that the $1.329 million rate base adjustment, calculated in accordance with well-settled Board policy, appropriately reflects consolidated tax savings achieved by RECO through offsetting tax losses of affiliates with RECO's positive taxable income. Further, the Board **ORDERS** RECO to submit a consolidated tax adjustment in every future base rate case filing. The future consolidated tax adjustments are to be made utilizing the methodology that Staff utilized to calculate its $1.329 million adjustment as shown on Exhibit 4 of this order.

3. Pro Forma Operating Income

With the exception of certain specific issues discussed in this section, the Board **HEREBY ADOPTS** and incorporates by reference as if completely set forth herein, the ALJ's Initial Decision with respect to RECO's pro forma operating income.

a) Enhanced Service Reliability

As previously discussed, RECO proposed to include estimated O&M expenses of $1,141,000 associated with its enhanced service reliability programs. These programs include $124,000 for street lighting protection, $550,000 for tree trimming enhancements, $233,000 for pole inspection and treatment, $170,000 for a fault indicator program and $64,000 for transmission line enhancements. (RECO-30; P-2, Sched. 10, "8+4" Update). RECO claimed these programs will provide customers with enhanced service reliability. Company witness Marino asserted that these programs are "over and above RECO's base reliability initiatives and . . . designed to improve reliability of service to our customers." (RECO-30 at 26-27). He further testified that if the Board does not approve these initiatives, "RECO does not intend to implement" them. Id.

The ALJ adopted the positions of Staff and the RPA that the proposed additional operation and maintenance and depreciation expenses associated with these programs should be disallowed. (I.D. at 45). He agreed with the RPA and Staff that:

> N.J.S.A. 48:2-23 requires the company to provide safe adequate and proper service and to keep its plant in condition to enable it to do so. The enhanced service reliability expense proposed by the company fits into the company's statutory responsibility.
>
> [I.D. at 45].

The ALJ also concurred with the recommendations of Staff and the RPA on this issue set forth in Staff's Initial Brief at 51-52, 72-73 and the RPA's Initial Brief at 42-43, 66. (I.D. at 50).

The Board agrees with the ALJ's decision that the utility has the obligation to provide safe, adequate and proper service, and that these types of reliability measures (for street lighting protection, tree trimming, pole inspection and treatment, etc.) should be part of its ongoing service reliability obligations. Nonetheless, because of the Board's utmost concern with respect to reliability issues, and to ensure that customers receive the benefits of the reliability enhancements sought by the Company, the Board **HEREBY MODIFIES** the ALJ's decision to permit the Company to include in its Phase II filing, authorized supra, a request for recovery of the costs of the reliability enhancements sought in this case, but appropriately disallowed by the ALJ based upon the record reflecting that the enhancements had not actually been performed. The Company shall have the burden of proof to demonstrate that these measures have been implemented and that any expenditures for which recovery is sought are reasonable and are above and beyond the level of operations, maintenance and depreciation expenses authorized herein.

b) Net Pension/Other Post Employment Benefits

The Board **HEREBY** **ADOPTS** the I.D. concerning pension expense and OPEBs. However, an additional pension expense related issue in this case is RECO's proposal to continue to defer the difference between pension expenses allowed in rates and actual pension expenses in accordance with the terms of a Settlement Agreement it entered into in its 1992 rate case, BPU Docket No. ER91030356J (Order dated January 10, 1992).

The RPA argued that there is no compelling reason why this deferred accounting mechanism, established in the context of a rate case settled over a decade ago, should continue. It asserted that pension expenses should be treated the same as any other expenses, such as wages, salaries, medical and dental expenses and outside consultants. It is well established that the appropriate ratemaking formula for expenses of this sort is for the Board to determine an appropriate annual level of rate recovery based on the record presented during a rate case. The RPA maintained that RECO should not continue to have special treatment related to pension expenses whereby it can compare the actual expenses incurred to the expense allowance built into its rates and defer the difference for reconciliation (amortization) in the next base rate case.

Staff noted that the 1992 Settlement Agreement was adopted by the BPU to give RECO time to adjust to a new accounting standard for OPEBs established by SFAS 106. (SIB at 72). RECO agreed that this was the original intent of permitting deferred accounting for pension expenses.

RECO was the only utility that was allowed to use this deferred accounting. SFAS 106 has now been in effect for over a decade, allowing RECO ample time to change its OPEB accounting procedures. Moreover, the record reflects that RECO's parent company, CEI, no longer uses deferred accounting for pension and OPEB expenses. Thus, the Board **HEREBY** **FINDS** that there no longer exists any reason to continue treating RECO's OPEB and pension expenses differently from any other expense item included in the cost of providing service to customers. Accordingly, the Board **HEREBY** **DIRECTS** RECO to cease its deferred accounting treatment for pension expense and OPEBs relative to the difference between the amounts allowed in rates for pension expense and OPEBs and the corresponding expenses booked.

c) Depreciation Expense and Depreciation Reserve

At issue in this proceeding is the ratemaking treatment of estimated future net salvage, as it pertains to the Company's annual depreciation expense and the level of RECO's excess depreciation reserve. The final annual depreciation expense positions of the parties based upon twelve months of actual data were as follows:

RECO	--	$4,866,000
RPA	--	$3,954,000
Staff	--	$4,063,000

The ALJ adopted Staff's test-year depreciation expense recommendations. (I.D. at 49). Staff essentially supported the RPA's proposal to remove net negative salvage from the depreciation rate, but recommended a 10-year average net salvage allowance, as opposed to the 5-year average net salvage allowance proposed by the RPA.

Annual depreciation expense is determined by applying depreciation rates to plant investment. Typically, there are two components associated with the recovery of investment in plant. First, the utility is entitled to recover the plant investment itself. Second, even though the expense has not yet been incurred, the utility is entitled to recover estimated future net salvage.

Net salvage refers to the difference between gross salvage and the cost of removal of the plant. Gross salvage is the amount recorded due to the sale, reimbursement, or reuse of retired property. The cost of removal is the cost of disposing of retired depreciable plant. Net salvage is positive when gross salvage exceeds cost of removal. Conversely, net salvage is negative when cost of removal exceeds gross salvage. A positive net salvage ratio reduces the depreciation rate and depreciation expense, while a negative net salvage ratio increases the depreciation rate and depreciation expense.

In this proceeding, the RPA's depreciation witness, Mr. Majoros, presented convincing evidence that although RECO incorporated $897,000 of annual negative net salvage recovery in its test year depreciation expense for transmission, distribution and general plant, over the five-year period ending 2001, RECO had only experienced $43,000 of annual negative net salvage on average. (RPA Exh. MJM-1, Sch. III-2). He testified that the mismatch between the Company's actual net salvage experience and the net salvage amount included in RECO's test year depreciation expense for transmission, distribution and general plant results from RECO's inclusion of future inflation in estimating net salvage expense. (R-36 at 15).

The principle underlying Mr. Majoros' recommended net salvage allowance approach was recognized by the National Association of Regulatory Utility Commissioners ("NARUC") in its publication entitled "Public Utility Depreciation Practices" ("NARUC depreciation manual"). Moreover, as pointed out by the RPA, in 2001 the Financial Accounting Standards Board ("FASB") adopted FAS 143 setting forth the treatment of Asset Retirement Obligations ("AROs") for financial statements issued for fiscal years beginning on or after June 15, 2002. (R-37). Mr. Majoros testified that the concept underlying FAS 143 is that "future costs will not be included in costs charged to current operations or costs charged to ratepayers unless the company can demonstrate a legal obligation to incur those costs." (4T. at 190).

The record reflects that RECO has not claimed any AROs in its books for its transmission and distribution assets. The absence of AROs for transmission, distribution and general plant categories means that RECO does not have any legal obligations to incur any negative net salvage either now or in the future for those assets. Having considered the various arguments of the parties, specifically the comparison of the negative net salvage proposed in test year rates to those actually experienced over the five-year period ending 2001, the Board **HEREBY ADOPTS** the ALJ's recommendation to reduce RECO's depreciation rates in accordance with the recommendations of the RPA and Staff. The Board **HEREBY FINDS** the proposed utilization of a net salvage allowance in depreciation expense is reasonable as it more closely aligns the amount recovered in base rates with the historical level of expenses incurred. Additionally, the Board **HEREBY ADOPTS** the ALJ's recommendation to use Staff's ten-year average rather than RPA's five-year average and **HEREBY ORDERS** that RECO be permitted to recover an amount equivalent to a ten-year average of its net salvage expense. The Board concurs with Staff that a ten-year average of RECO's depreciation expense provides a broader perspective of actual experience.

With respect to the depreciation reserve, all the parties agreed that RECO possesses a significant excess depreciation reserve. RECO calculated a depreciation reserve excess of $11.8 million, which it proposed to credit to its ratepayers over a 20-year amortization period. This translates to a $588,000 reduction in depreciation expense. The RPA argued that the proper reserve excess is $22.1 million, based upon the Company's asset lives and the exclusion of future net salvage assumptions from the depreciation rates. It did not object to RECO's proposed 20-year amortization period for the excess and thus asserted that the annual expense reduction should be $1,103,000.

Although the ALJ adopted the 20-year amortization schedule for crediting excess depreciation back to ratepayers, the Board **HEREBY MODIFIES** the Initial Decision so that the $22.1 million excess reserve is amortized back to ratepayers over ten years. The Board finds that shortening the amortization schedule to return the excess depreciation back to ratepayers more quickly is appropriate and reasonable in order to help offset the impact on customers of the rate increases associated with the recovery of deferred balances that were incurred over the Transition Period, as well as the increase in BGS charges.

d) Common Expense Allocation

In its December 2002 update, RECO reflected an increase of $388,000 in operating expenses to adjust other O&M expenses for the change in common expense allocation factors between O&R and RECO from 2002 to 2003. Common expenses include customer accounting, customer service and administrative and general functions for both O&R and RECO that are allocated to each company annually, based on the prior calendar year's data. The RPA contends that the $388,000 increase was introduced "at the eleventh hour, with no support in terms of explanatory testimony or supporting work papers and source documentation." (RPA Initial Brief at 67).

According to the record, the common expense allocation ratios are based on the Board-approved Joint Operating Agreement ("JOA") between RECO and O&R. The JOA allocations have been considered and addressed in several of RECO's past rate proceedings. As RECO witness Marino explained, the common expense allocation ratios are established each year as information on the number of customers for the prior year becomes available. Thus, in its December 2002 update, filed on January 17, 2003, RECO updated the common expense allocations for 2003 to reflect ratios based on the recent available 2002 data, consistent with the JOA. Moreover, RECO supplied supporting work papers and introduced them into evidence. (RECO-12A Tab 17 (common expense allocations)). The Board **HEREBY FINDS** that RECO is entitled to proper expense recognition for the update to the common expense allocation.

Notwithstanding this finding, it must be noted that both the RPA and Staff identified a "double count" due to the apparent inclusion of separate updates to pension and OPEBs expenses in FERC account 926. In its Reply Brief, RECO conceded that it had made an accounting error and agreed to eliminate it in the next update filing. RECO Reply Brief at 55. RECO quantified the amount in error to be $163,000 and reduced its common expense allocation of $388,000 by this amount in its "12+0" update filing in May 2003. Staff agreed with this adjustment. Moreover, although the ALJ did not specifically address the issue, he implicitly adopted the Staff position by virtue of adopting Staff's overall operating income position.

The Board **HEREBY ADOPTS** RECO's proposed 12-month actual expense adjustment of $225,000 related to its common expense allocation, as this amount appropriately reflects the elimination of the double-count. Additionally, the Board **HEREBY ADOPTS** Staff's recommendation to include RECO's proposed 12-month actual adjustment of $31,000 for maintenance costs of additional telephone lines installed due to the implementation of the BGS hourly energy pricing program. Although RECO proposed this adjustment in its "12+0" updates, which were filed after the hearings before the ALJ had been concluded, in light of the Board's implementation of BGS hourly pricing for certain large customers, as well as the fact that the additional expenses associated with the hourly pricing program have not been opposed by any party, the Board finds that these costs should be included in rates.

e) Interest on Customer Deposits

In its "12+0" update, RECO proposed a $38,000 expense representing interest expense at the Board approved 1.82% rate for customer deposits. The RPA proposed that the interest expense be calculated based upon the customer deposit level included as a deduction to RECO's rate base. This equates to $32,000. Since the "12+0" updates were filed after the close of the record, the ALJ did not specifically address this issue.

The Board finds reasonable and **HEREBY ADOPTS** the recommendation of Staff and the RPA to reflect only that portion of interest expense on customer deposits associated with the customer deposit balance deducted from rate base.

f) Miscellaneous Issues

The ALJ did not specifically address certain issues, but his conclusions with respect to pro-forma operating income indicate that he adopted Staff's position. Accordingly, the Board **HEREBY ADOPTS** Staff's recommendations with regard to these issues, which include miscellaneous service revenues, electric rent revenues and removal of certain incentive compensation expenses.

With respect to miscellaneous service revenues, RECO proposed test year revenues in the amount of $6,000. The RPA asserted, and Staff agreed, that this amount was too low, considering the historical revenues in this account for years 1999 ($45,000), 2000 ($14,000), 2001 ($18,000) and January 1 through October 31, 2002 ($23,000). Staff and the RPA recommended increasing RECO's miscellaneous service revenues projection of $6,000 by $19,000, bringing the level of miscellaneous service revenues in the test year up to the 4-year average of $25,000. The Board **HEREBY FINDS** this adjustment reasonable, because it more closely reflects the historical revenue trend experienced by RECO.

Similarly the Company included $9,000 for electric rent revenues, which amount appears to be understated when compared to historical revenues generated in this account over the past four years ($53,000 in 1999; $61,000 in 2000; $64,000 in 2001 and $76,000 from January 1 through October 31, 2002). The four-year average is $64,000. The Board **HEREBY FINDS** it appropriate to increase the revenues by $55,000 bringing the level of electric rent revenues in the test year up to the four-year average. The Board **FINDS** this adjustment to be reasonable since the result more closely reflects the historical revenue trend experienced by RECO.

With respect to incentive compensation, RECO proposed to include in rates additional annual incentive compensation in the amount of $421,000. The RPA and Staff recommended disallowing this expense, asserting that such incentive programs should be supported by shareholders, not ratepayers. The Board, in accordance with its decision in I/M/O the Petition of Jersey Central Power and Light Company for Approval of Increased Base Tariff Rates and Charges for Electric Service and Other Tariff Revisions, BRC Docket No. ER91121820J (dated June 15, 1993), agrees with the RPA and Staff. In that case, the Board specifically found that incentive compensation or "bonus" expenses of this nature should not be recovered from ratepayers, noting that:

> The current economic condition has impacted ratepayers' financial situation in numerous ways, and it is evident that many ratepayers, homeowners and businesses alike, are having difficulty paying their utility bills or otherwise remaining profitable. These circumstances as well as the fact that the bonuses are significantly impacted by the Company achieving financial performance goals, render it inappropriate for the Company to request recovery of such bonuses in rates at this time. Especially in the current economic climate, ratepayers should not be paying additional costs to reward a select group of Company employees for performing the job they were arguably hired to perform in the first place.
>
> [I.D. at 4].

See also, I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Changes, BPU Docket No. WR00060362 (dated June 6, 2001) at 25.

The Board continues to believe that incentive or "bonus" compensation should not be paid for by New Jersey ratepayers. New Jersey ratepayers are entitled to safe, adequate and proper utility service at just and reasonable rates, and should not, in our view, be required to pay incentives or bonuses for the utility to provide such service. Some New Jersey ratepayers continue to face many of the same economic difficulties which existed at the time the Board formulated the above policy, and which, in the Board's view, justify its continuance. Accordingly, the Board **HEREBY ORDERS** that all of RECO's proposed incentive compensation should be disallowed from rates.

4. Cost of Service Study / Rate Design

a) Bad Check and Reconnection Charges

Since the ALJ's I.D. resulted in a rate decrease, the ALJ recommended that there be no change made in the bad check charge and the reconnection charge. The Board **HEREBY REJECTS** the ALJ's findings concerning these charges.

The Company proposed without objection from either Staff or the RPA, that a returned check charge be applicable to all RECO customers. Currently the charge applies only to non-residential customers. The Board finds that it is reasonable for RECO to assess a bad check charge on residential customers whose check has been returned.

While there was consensus on the imposition of a returned check charge, the parties disagreed as to the appropriate amount to be charged. Currently, RECO charges $3.50 plus any amount the Company is required to pay its bank for handling such checks. Staff and the RPA argued that continuation of this proposed fee structure, particularly if it were to also apply to residential ratepayers, could lead to customer confusion if different banks charge different fees for dishonored checks. Therefore, Staff and the RPA recommended a flat fee of $7.00 based upon the Company's actual per-returned check costs for the twelve months ended June 30, 2002. The Board finds this to be a reasonable proposal, supported by the record, and thus, **HEREBY ADOPTS** the recommendations of Staff and the RPA that a flat fee of $7.00 be established.

With respect to reconnection charges, RECO proposed to increase its reconnection fee to $27.00 for all hours of the day. RECO's current tariff provides that, in certain specified circumstances, RECO will restore service for $7.00, if the reconnection is made before 3 p.m. on a weekday. The current fee rises to $21.00 if service is restored after 3 p.m. on a weekday or prior to the next working day. The RPA recommended a $15.00 reconnection charge, which it asserts is not far out of line with the reconnection charges of the other three electric utilities. Staff recommended a compromise position which would set the reconnection charge at $21.00 all of the times of the day.

Having carefully considered the positions of the parties on this issue, the Board is persuaded that $21.00, which is the amount the Company currently charges at higher cost times (weekdays after 3:00 p.m. and on weekends), more closely reflects the costs associated with the restoration of service at all points during the day than the rates proposed by RECO and the RPA. Additionally, in the Board's view, a $21.00 charge appropriately balances the RPA's concern that the Company may recover more than necessary for reconnections performed before 3:00 p.m. on a weekday against the possibility that the Company will receive insufficient recovery for restorations of service performed after 3 pm on a weekday or prior to the next working day. Moreover, since the fee will be the same for all times of the day, it provides customers with the flexibility to request service any time during the day, without disrupting their ability to work. It should also be noted that $21.00 is also in line with the $20.00 reconnection charge the Board recently approved for PSE&G during its electric base rate case. See I/M/O the Petitions of Public Service Electric and Gas Company for Approval of Changes in Electric Rates, For Changes in the Tariff for Electric Service and For Other Relief, et al. BPU Docket Nos. ER02050303, ER02080604, EM00040253, ET01120830, EO02080610, EO01120832, EO02110854, GR01040280 (Summary Order dated July 31, 2003).

b) Line Extension Charge

RECO proposed to raise the charges associated with the extension of lines and facilities to new residential subdivisions and multiple-occupancy buildings. RECO indicated that, pursuant to N.J.A.C. 14:5-4.1, Item No. 15A of the General Information Section of its Tariff (Leaf 8 through Leaf 9E) provides that the extension of electric distribution lines necessary to furnish an electric system to new residential subdivisions having three or more building lots, or to new multiple-occupancy buildings, shall be made underground. Moreover, pursuant to N.J.A.C. 14:5-4.4, Item No. 15A requires an applicant to pay the differential between the cost of the system installed underground and the cost of an equivalent overhead distribution system, as determined from the component unit charges outlined in Appendix A, and supporting Exhibits I, II and III, set forth within Item No. 15A of the Tariff. These charges were last updated in 1987.

RECO asserted that the proposed increase in unit charges is due primarily to an increase in labor rates and material costs associated with these charges since 1987. As set forth in Exhibit A of RECO's petition, the impact to applicants based on the revised charges is an annual increase of $290,200 for contributions from applicants for new residential subdivisions and multiple occupancy buildings. During the hearings, this amount was revised to $296,291. (T. 2/20/03 at 14). The increase was calculated by taking a representative sampling of jobs and pricing out the contribution level using the new unit cost rates and comparing them with the contribution level from current unit cost rates. The total increase in the contribution amount determined the weighted growth rate for the contribution in the sampling. The weighted growth rates were then applied against the average of the annual contributions received for the period 1997 through 2001. (RECO-13 at 1-3).

Neither Staff nor the RPA took a position on this issue. The Board **HEREBY ADOPTS** RECO's proposal on line extension charges for new residential subdivisions and multiple occupancy buildings, which updates the charges to reflect current costs.

c) Late Payment Fee

RECO proposed to impose late payment charges on non-residential customers, except non-residential state, county or municipal government customers. It seeks to assess late payment charges on overdue bills for non-residential customers at the rate of 1.5% per month. The interest would be calculated on the outstanding balance, including any unpaid late payment charge amounts applied to previous bills which were not received by the Company when the next regular bill was calculated.

The RPA did not take a position on this issue. Staff supported RECO's position as consistent with current Board policy. The Board **HEREBY ADOPTS** RECO's proposed late payment fee for non-residential and non-governmental customers.

5. Summary of Board Findings, Base Rate Case

a) Revenue Requirements (Rate Base and Operating Income)

Having accepted the Initial Decision with the modifications noted herein, and as summarized in Exhibit 3 attached hereto (including inter alia, an amortization of the Company's excess depreciation reserve over 10 years, Staff's recommended consolidated tax adjustment and an allowed overall rate of return of 8.02%) the Board **HEREBY FINDS** the Company's rate base to be $112.316 million, its operating income requirement to be $9.004 million and its pro forma operating income at current rates to be $13.266 million, or $4.262 million more than its operating income requirement. After providing for income taxes and uncollectible accounts (applying a retention factor of 0.5905) the Company's equivalent excess revenue requirement is $7.217 million. Accordingly, the Company is **HEREBY DIRECTED** to reduce its base rates by $7.217 million.

b) Rate of Return

Having rejected the Initial Decision's findings on rate of return, we **HEREBY ACCEPT** the capital structure of 54% long-term debt and 46% common equity recommended by Staff. We additionally accept Staff's recommended weighted average cost of long-term debt of 6.54%. [39] In recognition of the more leveraged capital structure we find appropriate for a "distribution only" Company, we **HEREBY FIND** that the rate of return on common equity the Company shall be permitted to earn is 9.75%. We additionally **FIND** that the overall rate of return the Company shall be permitted to earn is 8.02%.

[39] O&R's weighted average cost of long term debt of 6.78% as of April 30, 2003 (Exhibit P-4, Schedules 1 and 2 included in the "12+0" update), adjusted to reflect replacement debt for the $35 million of O&R's 6.56% Series D debentures redeemed on April 1, 2003. An interest rate of 4.5% was assumed for the replacement debt (the rate assumed by the Company, as indicated on page 6 of the supplemental testimony of RECO witness Kane included with the "12+0" update).

c) Bad Check and Reconnection Charges

Having rejected the Initial Decision's finding on these charges, the Board **HEREBY ORDERS** that the Company's bad check charge be raised from $3.50 to a flat fee of $7.00, and that its reconnection charge be raised from $7.00 to $21.00 for all time periods. Additionally, the Board **HEREBY ADOPTS** the Company's proposal on line extension charges for new residential subdivisions and multiple occupancy buildings as well as the Company's proposed late payment fee for non-residential and non-governmental customers.

d) Accounting for Pension Expense and OPEBs

Having adopted the Initial Decision's findings on pension expense and OPEBs, the Board, for the reasons set forth herein, additionally **HEREBY DIRECTS** the Company to cease deferral accounting for these expenses (deferring the difference between the amounts allowed in rates and the corresponding amounts booked for these expenses).

e) Phase II Proceeding

We **HEREBY MODIFY** the Initial Decision and authorize the Company to file a petition on or before September 1, 2004 [40] to address the ratemaking treatment of the Upper Saddle River and Darlington projects, including the issue as to whether they are transmission-related (subject for ratemaking purposes to the jurisdiction of the FERC) or distribution-related (subject for ratemaking purposes to the jurisdiction of the Board). Given our continuing concern with and the critical importance of maintaining service reliability, the Company is additionally authorized to request recovery of the cost of the service reliability enhancements it sought in this proceeding, but the record reflected and the ALJ appropriately concluded, had not actually been performed.

f) Other Issues

The Initial Decision did not specifically address certain issues but instead implicitly adopted Staff's position on these issues by adopting Staff's pro-forma operating income. Accordingly, the Board **HEREBY ADOPTS** Staff's recommendations with regard to these issues, including miscellaneous service revenues, electric rent revenues and removal of certain incentive compensation expenses, as set forth more fully herein and in Exhibit 3. The Board additionally **ADOPTS** Staff's recommended expense adjustment of $0.225 million related to the Company's common expense allocation after the elimination of the "double counting" of a portion of common expenses, $0.031 million of telephone line maintenance expenses associated with hourly energy pricing, and the inclusion of related energy pricing investment, which was not opposed by any party.

[40] The Company's Phase II petition was filed on March 3, 2004.

g) Rate Design

The ALJ having made no finding on rate design, the Board **HEREBY ADOPTS** the recommendation of Staff and the Company, and **HEREBY DIRECTS** that the $7.217 million base rate reduction be implemented on an across the board basis, with the exception of a non-contested reduction in the differential in the winter tail block rate for Service Classification No. 5.

VI. EFFECTS OF ALL RATE CHANGES

In addition to reflecting the base rate reduction, the interim recovery of the deferred BGS balance, the revised SBC, the unchanged ECA, as well the expiration of the Temporary Credit implemented as part of the year-four rate reduction mandated by the EDECA, all as provided herein, the Company will implement an increase in its BGS charges effective August 1, 2003 to reflect the results of the statewide auction previously approved by the Board by Order in Docket No. EX01110754 dated February 6, 2003. The Company estimates that for its customers taking “fixed price” BGS service, the effect of all rate changes will be to increase its annual revenue by $19.929 million before application of the 6% New Jersey Sales and Use Tax, and $21.125 million with the tax included, or by approximately 16%. For the average residential customer (SC-1) using 880 kwh per month, the increase is estimated to be about 15.4% (from $85.21 per month to $98.36 per month).

DATED: **4/20/04**

BOARD OF PUBLIC UTILITIES
BY:

SIGNED

JEANNE M. FOX
PRESIDENT

SIGNED

FREDERICK F. BUTLER
COMMISSIONER

SIGNED

CAROL J. MURPHY
COMMISSIONER

SIGNED

CONNIE O. HUGHES
COMMISSIONER

SIGNED

JACK ALTER
COMMISSIONER

ATTEST:

SIGNED
KRISTI IZZO
SECRETARY